D.P.U. 95-1A -1

Application of Boston Edison Company:

(1) under the provisions of G.L. c. 164, § 94G, and the Company's tariff, M.D.P.U. 592-A, for quarterly review by the Department of Public Utilities of the annual fuel and purchased power adjustment charge and for approval of interim changes in the New Performance Adjustment Charge and Fossil Generation Performance Adjustment Charge to be billed to the Company's customers pursuant to meter readings in the billing months of February, March, and April 1995; and

(2) for approval by the Department of rates to be paid to Qualifying Facilities for purchases of power pursuant to 220 C.M.R. §§ 8.00 <u>et</u> <u>seq.</u> and M.D.P.U. 545-A. The rules established in 220 C.M.R. §§ 8.00 <u>et</u> <u>seq.</u> set forth the filings to be made by utilities with the Department, and implement the intent of sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978; and

(3) under the provisions of G.L. c. 164, § 94G, for review by the Department of the performance of the Company's generating units for the period of November 1, 1993 through October 31, 1994.

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I. INTRODUCTION

On January 6, 1995, pursuant to G.L. c. 164, § 94G and 220 C.M.R. §§ 8.00 et seq. Boston Edison Company ("BECo" or "Company") notified the Department of Public Utilities ("Department") of the Company's intent to file a quarterly change to its fuel charge in conformance with its tariff, M.D.P.U. 592-A, and to its qualifying facility power purchase rates in conformance with its tariff, M.D.P.U. 545-A. The Company requested that both these changes be effective for bills issued pursuant to meter readings in February, March and April 1995. This matter was docketed as D.P.U. 95-1A. The Company also submitted to the Department for review the performance program data for the Company's generating units for the November 1, 1993 through October 31, 1994 performance year.[1]

Pursuant to notice duly issued, the Department held a public hearing on the Company's application on January 26, 1995, at the Department's offices in Boston. The Attorney General was the only intervenor in this proceeding. At the January 26, 1995 hearing, the Department continued the proceeding in order to investigate any performance variances from the goals that had been established for the Company's generating units in Boston Edison Company, D.P.U. 93-146 (1993) (Tr. at 7). BECo did not oppose deferring consideration of these issues.[2] This matter was docketed as D.P.U. 95-1A-1.

The Department held four days of hearings addressing generating unit performance issues from March 14, 1995 through March 28, 1995. During the hearings, the Company presented five

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1 In accordance with G.L. c. 164, § 94G, once per year, the Company is required to file with the Department the actual performance results of generating units in its performance program. Typically, the Company provides this data concurrently with its January fuel charge filing.

2 On February 5, 1995, the Department issued an Order in Boston Edison Company, D.P.U. 95-1A establishing the Company's fuel charge for the billing months of February, March, and April 1995.

witnesses: Jean Bellefeuille, the material and component manager at Pilgrim Nuclear Power Plant ("Pilgrim"); Thomas F. Carroll, performance and reliability coordinator for the Company; Timothy J. Bedard, department manager of the Mystic Power Station ("Mystic"); Paul A. Flaherty, department manager of the New Boston Power Station ("New Boston"); and John S. Embriano, division manager at the generation services department of the Company. The record contains 188 exhibits and 32 record requests. The Attorney General filed a brief on April 18, 1995, and the Company filed its brief on May 3, 1995. The Attorney General filed a reply brief on May 10, 1995, and the Company filed its reply brief on May 16, 1995.

II. PERFORMANCE REVIEW

A. Standard of Review

The Department is authorized to set a quarterly fuel charge for a company's recovery of prudently incurred costs for fuel and purchased power. G.L. c. 164, § 94G(b). To aid in determining the prudence of such costs at a later date, the Department is required to set performance goals annually for the generating units that provide electric power to jurisdictional electric companies. G.L. c. 164, § 94G(a). In goal-setting proceedings, a company proposes targets, subject to Department review, for both individual generating units and the company's overall system. The Department reviews the proposed goals and issues an Order establishing both unit and system-wide performance goals for the subsequent twelve-month period.

In particular, G.L. c. 164, § 94G(a) states in part that each company

> shall describe for the time period or periods designated reasonably attainable targets which shall include a thermal efficiency target for the performance of the company .... Such program also shall provide for the efficient and cost-effective operation of individual generating units by an electric utility company in meeting the minimum needs of each unit of said company to maintain sufficient reserves of power for purposes of reliability and efficiency. Such program also shall describe

> the historic data, industry standards or reports, simulation models or other information and techniques upon which projections of the company's performance are based and shall include, as goals for individual and system plant performance, availability, equivalent availability, capacity factor, forced outage rate, heat rate on a unit by unit basis and such other factors or operating characteristics required by the Department. Any such program may specify a value or a range of values for the operating characteristic in question and shall reflect operating conditions when overall performance is optimized.

The availability factor ("AF") of a unit is the fraction of time during which the unit is capable of generating power at any level. AF, which is expressed as a percentage, measures how often a unit was available to generate power, but is not a measure of the amount of power generated. AF takes into account the effect of planned outage-hours ("POH") and unplanned outage-hours ("UOH") on a unit's availability. POH are outage-hours that are scheduled well in advance of the date on which they occur. UOH comprise five categories of outage-hours. The first three categories ("UOH 1, 2 and 3"), also known as forced outage-hours ("FOH"), are outages caused by conditions that require removing a unit from service on, at most, a few days' notice. The fourth category ("UOH 4") represents maintenance outage-hours ("MOH"), which are outages that can be delayed beyond the end of the next weekend, but that take a unit out of service before its next planned outage. In the fifth category ("UOH 5") are outage-hours which extend a planned outage beyond its scheduled duration. The formula for AF is a ratio of period hours ("PH"), less POH and UOH, to PH; that is

$$AF = \frac{PH - POH - UOH}{PH}$$

The equivalent availability factor ("EAF") of a unit is the fraction of maximum generation that a unit would be able to produce if limited only by outages and deratings. Deratings are reductions in a unit's maximum power level. They can result from either unit conditions, such as equipment limitations, or seasonal conditions, such as ambient water temperature or environmental restrictions. EAF, expressed as a percentage, differs from AF in that it takes into account equivalent unit derated hours ("EUNDH") and equivalent seasonal derated hours ("ESDH"). EUNDH comprises equivalent planned derated hours ("EPDH") and equivalent unplanned derated hours ("EUDH"). Equivalent derated hours are calculated by multiplying the duration of each derating, in hours, by the number of megawatts by which the unit is derated, and dividing the product by the maximum capacity of the unit. Gross EAF is calculated by using the gross maximum capacity of a unit to calculate equivalent derated hours, while net EAF is calculated using equivalent derated hours based on net maximum capacity. Gross maximum capacity includes the capacity required to supply electricity to run the unit. Net maximum capacity ("NMC") is the maximum capacity available after station service requirements have been met. The formula for either net or gross EAF can be expressed as

$$EAF = \frac{PH - POH - UOH - EUNDH - ESDH}{PH}$$

Net capacity factor ("CF") is a ratio of the number of megawatthours ("MWH") a unit has generated during a period of time in excess of station service requirements, compared to the maximum it could have generated if it had produced its net maximum capacity during the entire period. CF indicates how much power a unit generated during a given period, compared to the maximum amount of power it theoretically could have generated during that period. CF is usually expressed as

$$CF = \frac{\text{Net Actual Generation}}{\text{NMC x PH}}$$

Forced outage rate ("FOR") measures the amount of time that a unit was completely out of service because of forced outages during a period, relative to the amount of time that the unit was actually in service during the same period. FOR takes into account the unit's FOH, but not the other types of unplanned outages. It is calculated by dividing FOH by the sum of FOH and service hours ("SH"). A unit's SH are the hours in a given period during which the unit was in service generating electricity. The formula for FOR can be expressed as

$$FOR = \frac{FOH}{FOH + SH}$$

Heat rate ("HR") compares the energy input used by a unit during a given period, expressed in British Thermal Units ("BTU"), to the electrical generation of the unit, in kilowatthours ("KWH"), during the same period. HR is a measure of a unit's thermal efficiency. Net HR is usually expressed as

$$HR = \frac{\text{Fuel Energy Consumed}}{\text{Net Actual Generation}}$$

In accordance with G.L. c. 164, § 94G, the Department conducts annual goal-setting proceedings with each company over which it has authority to do so. In these proceedings, the performance programs submitted by a company are reviewed and goals are developed for AF, EAF, CF, FOR, and HR based on the formulas described above. At the conclusion of goal-setting proceedings, the Department issues an Order establishing both unit and system-wide goals for a subsequent twelve-month performance period.

Also in accordance with G.L. c. 164, § 94G, the Department conducts annual performance review proceedings wherein actual performance data obtained during a company's performance period are reviewed and compared to the goals that had been set for that period in a prior goal-setting proceeding. Should a company fail to achieve one or more of the goals established for a performance period under review, the company must present evidence explaining such variance at the next fuel charge proceeding. G.L. c. 164, § 94G(a). The Department conducts an investigation into the circumstances behind each failure. These investigations typically involve a detailed review of activities surrounding particular generating units in order to determine whether a company, in operating and maintaining its units, followed all reasonable or prudent practices consistent with the statute.

Specifically, the Department must

> make a finding whether the company failed to make all reasonable or prudent efforts consistent with accepted management practices, safety and reliability of electric service and reasonable regional power exchange requirements to achieve the lowest possible overall costs to the customers of the company for the procurement and use of fuel and purchased power included in the fuel charge. If the department finds that the company has been unreasonable or imprudent in such performance, in light of the facts which were known or should reasonably have been known by the company at the time of the actions in question, it shall deduct from the fuel charge proposed for the next quarter or such other period as it deems proper the amount of those fuel costs determined by the department to be directly attributable to the unreasonable or imprudent performance.

G.L. c. 164, § 94G(a).

The Department's standard for determining the prudence of a company's actions appears at G.L. c. 164, § 94G.[3] If a company expects to recover its costs, including purchased power costs

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3 "The statutory context ... is provided by the authority granted the Department in G.L. c. 164, § 94G(a), to deduct from a fuel charge proposed for the next quarter the amount of those fuel costs determined to be directly attributable to a company's unreasonable or imprudent performance; and, in § 94G(b), to deduct that amount determined to be directly attributable to a company's defective operation of a unit. Each determination is to be

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incurred as a result of unit outages, the company must "demonstrate the reasonableness of energy expenses sought to be recovered through the fuel charge." G.L. c. 164, § 94G(b). The Department is directed to disallow such costs if (a) the company fails to sustain its burden of proof that its actions were prudent, or (b) despite the company's making a prima facie case, the Department concludes that the company's actions were imprudent and proximately caused the fuel costs or incremental replacement power costs whose recovery is sought.[4] G.L. c. 164, § 94G.

In applying this standard, the Department has relied on critical path analysis, a method for determining whether a challenged company decision or discrete work item conducted during an outage may be judged to have caused or prolonged the outage.[5] Boston

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made in light of the facts which the company knew or should reasonably have known at the time of the actions in questions." Boston Edison Co. v. Department of Public Utilities, 393 Mass. 244, 245 (1984).

4 For the purposes of this proceeding, incremental replacement power costs are the difference between the costs for power to replace a unit which is not available for service across a given period, and the fuel and operating costs that would have been incurred had that unit operated during the period.

5 Critical path analysis is a commonly-used planning tool in large engineering and construction projects. It may be applied prospectively (an "as-planned" critical path may be developed for use) during a project to direct activities, and retrospectively to assess the conduct of an outage and the prudence of outage management (an "as-built" critical path would reflect the sequences and durations of activities actually experienced). The result of a critical path analysis is a network graphically depicting a schedule of activities and their sequence, durations, logic, interrelationships, and dependencies.

The critical path through a generating unit outage is the chain of activities representing the shortest possible path through the last event of the outage. The sum total of the durations of each activity on the critical path defines an outage's total duration. If an activity on the critical path is delayed, by definition, an equal delay is realized in the completion of the outage. A complex outage may have more than one critical path; and these are known as concurrent or parallel critical paths.

The effect of a delay in an outage activity on the overall schedule can be assessed only against the critical path. An activity not on the critical path may be delayed but still have no effect on the duration of an outage or purchased power costs. But an activity

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Edison Company, D.P.U. 93-1A-A at 7 (1994); Fitchburg Gas and Electric Light Company, D.P.U. 87-5A-1, at 13 (1989); Boston Edison Company, D.P.U. 1009-G (1982).

A performance review addresses the performance of a company's units during the performance year. The performance of certain units in which that company has contractual rights to capacity or output, rather than ownership interests, is, in the first instance, the proper subject of other docket inquiries. In keeping with established precedent, should it be determined in other inquiries that imprudent or unreasonable actions resulted in lost availability of units from which a company also received power, the Department may disallow the recovery of resultant incremental replacement power costs incurred by that company, in order to protect ratepayers from the adverse consequences of any imprudence. Commonwealth Electric Company v. Department of Public Utilities, 397 Mass. 361, 366, n.2 (1986).

Since 1985, the Department has held that a company must refund to ratepayers incremental replacement power costs that result from imprudence committed by its independent contractors to whom the company delegates the responsibility for original or repair work. Boston Edison Company, D.P.U. 93-1A-A at 21 (1994); Boston Edison Company, D.P.U. 92-1A-A at 19-20, 42, 44 (1993); Nantucket Electric Company, D.P.U. 92-7B-A at 15 (1993); Boston Edison Company, D.P.U. 88-1A-A at 51 (1988); Boston Edison Company, D.P.U. 85-1B-2, at 15-18 (1985); Western Massachusetts Electric Company, D.P.U. 85-8F-2, at 12-13 (1985). A company may not insulate itself from responsibility for the conduct of its business by engaging contractors. Section 94G of G.L. c. 164 applies with equal force to a company's independent

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not on the prospective or "as-planned" critical path also may be so delayed as to become itself the actual critical path and be deemed so in retrospect. Delay on the critical path does not necessarily result from imprudence: the cause may be conditions not reasonably foreseeable or preventable, new regulatory requirements, etc.

contractors on the principle that providing electric service is part of an electric company's "nondelegable statutory obligations." Commonwealth Electric Company v. Department of Public Utilities,
397 Mass. 361, 366, n.2 (1986).

B. Overview

The Department sets goals for units that BECo owns and operates, units in which it has an ownership interest but does not operate, and units from which it receives power under life-of-the-unit contracts. In D.P.U. 93-146, the Department set goals for BECo's major units (Mystic Units 4, 5, 6, and 7; New Boston Units 1 and 2; Pilgrim; and Canal 1) and minor units (Connecticut Yankee; Wyman 4; L Street Jet; Mystic Jet; Edgar Jets; Framingham Jets; and Medway Jets).

The instant performance review focuses on the actual performance of the above units during the performance year ending October 31, 1994. As in prior years, the Company's January 1995 fuel charge filing included the actual performance data for that performance period and a discussion of performance-related activities. The Company provided a comparison of the actual operating results achieved by BECo's units to the goals set in D.P.U. 93-146 (Exh. BE-PANEL-3, at 1). This comparison has been reproduced as Table 1 in this Order.

The information in Table 1 shows that some of the Company's major units did not achieve their EAF goals. Certain major and minor units also failed to meet other goals established in D.P.U. 93-146. Accordingly, the Department investigated the reported variances between the established goals and the actual performance of units in the Company's supply portfolio.

C. Performance Issues and Findings

1. Pilgrim

a. Introduction

Pilgrim is a 670 MW nuclear unit, located at Rocky Point, Plymouth, Massachusetts. The unit has been in commercial operation since 1972, and is owned and operated by the Company.

During the November 1, 1993 through October 31, 1994 performance year, Pilgrim experienced three forced outages.[6] A November 5, 1993 forced outage that lasted for more than four days resulted from a feedwater heater failure. Another forced outage occurred on February 23, 1994, and resulted from the failure of the main steam isolation valve ("MSIV"). This outage lasted for more than nine days, because it was extended by six days to repair another motor-operated ("MO") valve in the feedwater system. The third forced outage occurred on April 22, 1994, and lasted for six and one-half days. The April 22, 1994 forced outage was associated with the reactor control rods' failure to pass a routine testing.

b. The November 5, 1993 Forced Outage

i. Background

On November 5, 1993, operators at Pilgrim manually initiated a plant shut-down to repair leaks in one of the plant's low pressure feedwater heaters (Exh. BE-JB-17, Tab 1). The leaks were suspected to be a tube leak in one of the "A" train low pressure feedwater heaters (Exhs. BE-JB-1, at 18; BE-JB-17, Tab 9).

The feedwater system at Pilgrim provides a dependable supply of pre-heated feedwater to the reactor vessel for improved plant efficiency (Exhs. BE-JB-1, at 14-15; BE-JB-17, Tab 10). The feedwater system pre-heats reactor vessel feedwater by condensing exhaust steam from both low pressure turbines and routing the condensate through feedwater heaters before

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6 Actually, during the performance year, Pilgrim experienced four forced outages. However, the fourth outage, which occurred on August 29, 1994, was completed on November 30, 1994, i.e., after the conclusion of the performance year, and will be addressed in the next performance review proceeding (Exh. BE-JB-1, at 3).

being fed into the reactor vessel (Exhs. BE-JB-1, at 14-15; BE-JB-17, Tab 10; AG-4; RR-AG-1). Three low pressure "A" train feedwater heaters are each 52 feet long, cylindrical, weigh approximately 53 tons, and are horizontally positioned (Exh. DPU-4; RR-AG-1). Each feedwater heater assembly includes a bundle of 1012 tubes which route feedwater flow, originating at the heater's tubesheet end, 45 feet into the heater and return to the heater's tubesheet end (Exh. DPU-4; RR-AG-1). In order to tie the bundle of tubes to the ends of each feedwater heater, and to ensure structural integrity, each feedwater heater assembly includes 17 tie rods of either one-half or three-quarter inch diameter (Exhs. BE-JB-1, at 20; DPU-4; AG-12, at 27; Tr. 1, at 10-11, 145-148). The tie rods are integral to the feedwater heaters and are in parallel with the tube bundles (id.). Each feedwater heater also includes a drain cooler section, which contains a separate heat exchanger located in the bottom half of the feedwater heater and which is fully enclosed by its top plate, sides of the feedwater heater shell, and its bottom plate, or shroud, which is fabricated from plate steel having several welded joints (Exh. AG-4).

According to the Company, as part of a preventive maintenance program at Pilgrim, the Company monitors the performance data of the feedwater system's operational parameters for signs of degrading or abnormal conditions (Tr. 1, at 86-87). On October 18, 1993, a systems engineer identified a leak in one of the low pressure feedwater heaters (Exhs. BE-JB-1, at 13-14, 18; BE-JB-17, Tab 2, 9). As the Company monitored the leak, trending indicated that the leak was increasing (Exh. BE-JB-1, at 15-16). The Company evaluated the potential magnitude of the problem and, because of the increasing leakage, decided that an immediate repair would be undertaken to minimize damage to the feedwater heater (Exhs.

BE-JB-1, at 17, 18; BE-JB-17, Tab 9). The Company estimated that power restrictions could be 80 to 85 percent if major damage occurred and on November 5, 1993 decided to shut down Pilgrim to repair the leak (id.).

Following Pilgrim's shut down, the fourth point "A" train feedwater heater ("E-102A feedwater heater"), was identified as the feedwater heater responsible for the leak (Exh. BE-JB-1, at 18). Upon internal examination of the E-102A feedwater heater, the heater was found to have eleven sheared feedwater tubes, two to three partially sheared tubes, and other tubes that were dented (id.). While most of the failed tubes were located adjacent to each other, some of the failed tubes were found in locations isolated from the others (Exh. BE-JB-17, Tab 3, at 4). The Company decided to plug a total of 44 tubes to close the leaking tubes and those representing likely future leakage paths (Exh. BE-JB-1, at 18-19). The Company completed the tube repairs on November 8, 1993 (Exh. BE-JB-17, Tab 5). Pilgrim was returned to service on November 9, 1993, thus the November 5, 1993 forced outage at Pilgrim had a duration of 109 hours (Exhs. BE-JB-1, at 16; BE-JB-17, Tab 5).

The Company investigated the likely causes of the failed tubes but was unable to conclusively determine a root cause (Exh. BE-JB-1, at 19). Among the possible causes investigated were (1) a manufacturing or material defect with the shroud in the bottom of the drain cooler section of the E-102A feedwater heater, just below the failed tubes, (2) a manufacturing or material defect in one or more of the failed tubes, and (3) an improperly low water level in the drain cooler section of the E-102A feedwater heater during start-ups after maintenance outages, which requires complete draining of the heater (Exhs. BE-JB-17, Tab 7, at 9; BE-JB-1, at 19, 20).

The Company explained that a first possible cause, a shroud defect, may have initiated as a weld crack or material flaw in the shroud that could have allowed steam into the drain cooler (Exhs. BE-JB-17, Tab 3, at 3; BE-JB-17, Tab 7, at 9; BE-JB-1, at 19, 20; Tr. 1, at 91). The steam could have caused cavitation-type erosion, or pitting, to the tubes leading to their failure (Exhs. BE-JB-17, Tab 3, at 3; AG-8). The Company further explained that a second possible cause, tube defects such as small holes, thin walls, dents, or pits, may have resulted from the tubes' manufacturing or material (Exhs. BE-JB-17, Tab 3 at 2, 4; BE-JB-17, Tab 7; AG-9). Finally, the Company explained that a third possible cause, an improper drain cooler water level, could have resulted in high vibration levels in the tubes during start-ups or low power operation, and subsequent damage to the tubes (Exhs. BE-JB-1, at 19, 20; BE-JB-17, Tab 7, at 9). According to the Company, if an insufficient amount of water is present in the E-102A feedwater heater during plant start-ups or low power operation, steam may be able to enter the drain cooler section at its inlet (Exhs. BE-JB-17, Tab 3, at 3; AG-11). If steam were to enter the drain cooler section of the heater, flashing and turbulence could produce vibrations that could result in the tubes banging each other at their baffle plate supports, with resultant damage to the tubes (Exh. BE-JB-17, Tab 3, at 3). The Company explained that the tube damage was not in the inlet area of the heater's drain cooler, but closer to the tube sheet, which is near the outlet area of the drain cooler (Exh. BE-JB-17, Tab 3, at 2). The Company further explained that because of the E-102A feedwater heater's design, the region near the outlet side of the drain cooler experiences an increase in condensate flow velocity making it susceptible to vibration (id. at 3). In addition, if velocities are substantially higher due to higher than design condensate flow or turbulence exists due to the presence of steam, vibration damage may occur (id.).

The E-102A feedwater heater was manufactured by Yuba Heat Transfer Corporation and was originally installed in 1984 (Exhs. AG-11; AG-12; Tr. 1, at 122). The vendor manual sets forth heater water level requirements before plant start-up in order to avoid the possibility of flashing at the drain cooler's inlet area with subsequent tube damage in the drain cooler area (id.). In addition, it is standard operating procedure at Pilgrim to fill and vent this equipment following maintenance (Exh. BE-JB-1, at 20; Tr. 1, at 122, 123, 126, 143; RR-DPU-1). Since the E-102A feedwater heater's installation, the heater has been opened and drained twice, during the November 5, 1993 outage and during an inspection performed in October 1994 (id.). The "System Fill, Vent, And Drain Instruction" procedure at Pilgrim is a generic procedure for any water-filled process system and provides instructions and practices to follow when draining or filling any water-filled system (RR-DPU-1, at 4). The "System Fill, Vent, And Drain Instruction" is intended to satisfy Pilgrim's Technical Specification 6.8.A, which requires written procedures to drain and fill water-filled systems (id.). Following the November 5, 1993 outage and October 1994 inspection, the feedwater heaters were filled and vented (Tr. 1, at 122, 126, 143). Although the Company does not have a separate procedure specifically for filling and venting the feedwater heaters, its operations staff has confidence that its generic fill and vent procedures ensure proper feedwater heater water levels after being drained (Tr. 1, at 125-127; RR-DPU-1). According to the Company, once established, the E-102A feedwater heater's water level is monitored and maintained by plant procedures three to four times a week (Exh. AG-10; Tr. 1, at 128). In addition, the E-102A feedwater heater's physical design configuration prevents self-draining since the heater drain is located higher than the mid-point of the drain cooler (Exhs. AG-4; AG-5; AG-11).

During an outage at Pilgrim in October 1994, the Company had inspected the E-102A feedwater heater and performed a root cause analysis of tube failures that had been identified and repaired during the November 5, 1993 outage (Exh. BE-JB-1, at 20). During the October 1994 inspection, the Company found an additional 24 heater tubes with varying degrees of damage in the area around the tubes that had been plugged during the November 5, 1993 repairs (Exhs. BE-JB-1, at 20; BE-JB-17, Tab 7, at 14, 26, 31). Because the additional tube failures were close to the tubes that had been previously repaired, although not immediately adjacent to them, the Company believed that the cause of the damage found in October 1994 was the same cause of the damage found in November 1993 (Exh. BE-JB-17, Tab 7, at 26, 31; Tr. 1, at 140).

During the October 1994 outage, an inspection of a valve in the E-102A feedwater heater drain line was also performed because problems had been experienced with the valve's opening and closing (Exh. BE-JB-17, Tab 7, at 4; Tr. 1, at 141). The Company found metallic debris in the drain line, including a piece of three-quarter-inch tubing, a half-inch rod threaded on one end, some gasket material, and various metallic corrosion products (Exhs. BE-JB-1, at 20; BE-JB-17, Tab 7, at 4). The debris found in the drain line matched the tie rods in the bottom of the E-102A feedwater heater in size, but was of a different alloy than that specified by the heater's manufacturer (Exhs. BE-JB-17, Tab 7, at 4; AG-14). The Company explained that, although the material found was not as the same material as specified by the manufacturer, it was possible that a different rod material had been used during the manufacturing of the E-102A feedwater heater since a chrome-molybdenum alloy had been used in manufacturing similar units built six months earlier (Exh. BE-JB-17, Tab 7, at 4).

Based on this information, the Company suspected that the metallic debris found in the drain line was a piece of tie rod and a spacer for baffle plate support and separation (Exhs. BE-JB-17, Tab 7, at 4; DPU-6; Tr. 1, at 17, 18, 139). The presence of metallic debris in the drain line led the Company to postulate a fourth possible cause of tube damage, i.e., that it might have been due to a loose tie rod located in the bottom center of the drain cooler (Exh. BE-JB-17, Tab 7, at 4). The Company eventually concluded that the most likely cause of the damaged tubes found in November 1993 was a loose tie rod that "unthreaded itself" from the tube sheet, then struck adjacent tubes (Exhs. BE-JB-1, at 20; BE-JB-17, Tab 7, at 4; DPU-6; Tr. 1, at 17, 18, 139). To prevent future tube damage, the Company installed cables inside tubes around the area that experienced the damage (Exh. BE-JB-1, at 21).

ii. Attorney General's Position

The Attorney General addresses on brief the four possible root causes of the failed tubes within the feedwater heater (Attorney General Brief at 5-9).

The Attorney General maintains that, if material or manufacturing defects in the bottom of the drain cooler shroud, or if material or manufacturing defects in the heater tubes were found to be the cause of the tube failures, it would indicate imprudence on the manufacturer's part which should be imputed to the Company (id. at 9).

The Attorney General maintains that it is unlikely that a loose tie rod was the cause of the tube failures (id. at 6, 7; Attorney General Reply Brief at 1, 2). The Attorney General claims that the manufacturer of the feedwater heater has never experienced a similar problem (Attorney General Brief at 6, 7). According to the Attorney General, it is unlikely that a rod could "unthread itself" and become loose in the heater (id.). Further, the Attorney General contends that the threaded piece of pipe found in a drain line in October 1994, which is the Company's sole basis for suspecting that a loose tie rod was the cause of the problem, is made from a different material from that of the feedwater heater (id.). The Attorney General further claims that additional tubes found damaged during the October 1994 inspection were damaged by vibration, not banging, which indicates that the later damage was not caused by a loose tie rod (Attorney General Reply Brief at 2, 3). In support, the Attorney General claims that the damage found during the October 1994 inspection could have been damage that the Company did not find earlier (id.).

The Attorney General contends that the damaged feedwater heater tubes might have been caused by the Company's failure to maintain an adequate water level in the drain cooler during plant start-ups (Attorney General Brief at 7-9). According to the Attorney General, the record demonstrates that, if the water level is allowed to fall below the level of the drain cooler inlet, steam can migrate into the drain cooler, causing turbulence and flashing, which, in turn, may damage piping in that section (id. at 7, 8). The Attorney General maintains that the feedwater heater vendor's manual sets forth water level requirements, but that the Company did not have a specific procedure or automatic process in place to ensure that an adequate water level was maintained in the heater during start-up procedures (id. at 8). According to the Attorney General, because of the inadequate water level, turbulence and flashing may have induced vibrations along the tubes that damaged the tubes five feet from the heater's outlet (id. at 8, 9). The Attorney General asserts that although the damage to the tubes occurred far from the inlet, the Company has offered no proof that turbulence and flashing cannot lead to damage far from the inlet (id. at 9).

The Attorney General maintains that the Company has not determined the cause of the problems which led to the November 5, 1993 outage at Pilgrim, and thus has not met its burden to prove the cause of Pilgrim's lost availability related to the November 5, 1993 outage (id. at 9-11). The Attorney General concludes that the Company should not be allowed to recover the replacement power costs associated with the November 5, 1993 outage at Pilgrim (id. at 11).

iii. Company's Position

The Company maintains that, in November 1993, although other possible causes of the feedwater heater leak existed, such as tube defects, at that time, the most likely cause of the tube failures was a manufacturing or material abnormality with the shroud in the bottom of the heater drain cooler (Company Brief at 14, 15, 17). During the October 1994 outage, the Company was able to further inspect the heater and continue its root cause analysis (id. at 16, 17). As a result of the inspection, the debris found in the drain loop line was affirmed by the vendor to be a piece of tie rod that may have come from a loose heater bundle tie rod in the damaged feedwater heater (id.). Furthermore, the Company claims that, because further tube damage found during the 1994 inspection occurred after the November 1993 repairs, a loose feedwater heater bundle tie rod was a possible root cause of the tube failures (id.). The Company therefore concludes that the loose heater bundle tie rod was the most likely cause of the feedwater heater tube failures in 1993 and 1994 (id. at 17).

The Company states that it evaluated the possibility of inadequate water levels in the feedwater heater during a plant start-up or low power operation to determine if this were, in fact, the cause of the heater tube failures (id. at 17). The Company maintains that it found no evidence to indicate that an inadequate water level ever occurred in the heater (id. at 18). The Company further concludes that water level did not have any role in the tube damage (id. at 20). Rather, the Company claims that the fill and vent procedure for the feedwater heater has ensured that adequate water levels have been maintained (id. at 18).

The Company insists that, although identifying the source of a leak in the feedwater system is difficult because of the hot and noisy environment during operation and the physical location of some of the system components, the Company's root cause analysis of the tube failures was relentless and extensive (id. at 3, 12, 15). The Company argues that, had it decided to pull the tube bundle from the feedwater heater for closer inspection, it would have added time to the outage (id. at 14, 15). The Company further argues that it was under an obligation to return the plant to operation as soon as there was reasonable assurance that the problem was corrected, therefore it did not perform a more detailed failure analysis (id. at 3, 12, 14, 15; Company Reply Brief at 2). According to the Company, this course of action minimized the duration of the outage and provided time to prepare for a more thorough tube inspection during the planned 1995 refueling outage (Company Brief at 14, 15, 17). Thus, the Company claims that it has met its burden to prove the cause of Pilgrim's lost availability related to the November 5, 1993 outage (id. at 15-16).

The Company claims that its action and decisions in response to the November 5, 1993 forced outage of Pilgrim were reasonable and prudent, and that Pilgrim's return to service was accomplished in an efficient, safe, and effective manner (id. at 11, 12). The Company claims that there is no basis to support the disallowance of any replacement power costs associated with the November 5, 1993 forced outage at Pilgrim (id. at 11, 12).

iv. Analysis and Findings

The record indicates that four possible causes of tube failures within the E-102A feedwater heater were identified by the Company. These include (1) a manufacturing or material defect with the shroud in the bottom of the drain cooler section, (2) a manufacturing or material defect in one or more of the failed tubes, (3) an improperly low water level in the drain cooler section of the heater during start-ups or low power operation, and (4) a loose tie rod.

In considering the possibility of manufacturing or material defects with the shroud, the record provides no evidence to indicate that manufacturing or material defects existed with the shroud. In addition, the record provides no evidence to indicate that steam entered the drain cooler as a result of shroud defects and subsequently caused cavitation-type erosion to the tubes resulting in their failure. Therefore, the Department finds that the feedwater heater tube failures cannot be attributed to manufacturing or material defects with the shroud.

In considering the possibility of manufacturing or material defects with feedwater heater tubes, the record provides no evidence to indicate that manufacturing or material defects existed in heater tubes. In addition, the record provides no evidence to indicate that manufacturing or material defects with feedwater heater tubes subsequently resulted in their failure. Therefore, the Department finds that the feedwater heater tube failures cannot be attributed to manufacturing or material defects with the feedwater heater tubes.

In considering the possibility that a feedwater heater bundle tie rod became loose, the Department finds it unlikely that the tube failures were caused by a loose heater bundle tie rod. According to the manufacturer, a tie rod unthreading itself and pieces being loose in the system have never before occurred (Exh. BE-JB-1, at 20). In addition, the Company failed to explain how a tie rod could "unthread itself" so as to become loose in the feedwater heater (Tr. 1, at 145). Furthermore, the record does not support the Company's claim that, because further tube damage found during the October 1994 inspection occurred after the November 1993 repairs, a loose heater bundle tie rod was the most likely cause of the feedwater heater tube failures in 1993 and 1994. The Company indicated that, had a tie rod become loose, the loose tie rod would have struck tubes immediately adjacent to the tie rod (Exh. BE-JB-17, Tab 17, at 9). The record demonstrates that the damaged tubes found during the October 1994 inspection were not all immediately adjacent to the tie rod or each other, but spread apart in the drain cooler section of the feedwater heater. Had a tie rod become loose and struck tubes immediately adjacent to the tie rod, as the Company claims, the damaged tubes found during the October 1994 inspection would have been immediately adjacent to the same tie rod that caused the 1993 tube damage. This supports the Attorney General's claim that the damaged tubes found during the October 1994 inspection were not damaged by a loose tie rod. This also suggests that the damaged tubes found during the October 1994 inspection was previous damage that the Company did not find earlier.

Furthermore, the type of material found in the drain line is inconsistent with the Company's claim that the damage resulted from a loose tie rod. The record indicates that during the October 1994 inspection the material found in the drain line, although having similar diameter and appearance as a piece of tie rod, was not made of 304 stainless steel as specified in the heater's design specifications. Furthermore, the record provides no evidence that Yuba did in fact manufacture the E-102A feedwater heater with spacers, tie rods, and baffles consisting of the chrome-molybdenum alloy that comprised the debris. This suggests that the material did not originate from the E-102A feedwater heater, although it may have originated from one of the upstream feedwater heaters, since the material was found in a drain line that serves all the feedwater heaters (Exh. AG-4; RR-AG-1; Tr. 1, at 142). Therefore, the Department finds that a loose tie rod did not damage the E-102A feedwater heater tubes found in 1993 and 1994.

In considering the possibility of damage as a result of low feedwater heater water levels maintained by the Company, the record does not demonstrate that the tube failures were caused by low water levels. The record does indicate that Pilgrim Technical Specifications require proper levels in water equipment and that Yuba sets forth proper drain cooler water level requirements to avoid feedwater heater tube damage in the drain cooler zone during start-up or low power operation (Exh. AG-11; RR-DPU-4, at 4). The record also demonstrates that Yuba and the Company understood that improper drain cooler water levels in the feedwater heater during start-up or low power operation could result in flashing and turbulence in the inlet area of the drain cooler, a condition that could result in vibration of the heater tubes in the drain cooler and damage to the tubes (Exhs. AG-11; BE-JB-17, Tab 3, at 3, 4; Tr. 1, at 122). Finally, the record demonstrates that damage to the heater's tubes as a result of low water levels can occur anywhere in the drain cooler (Exhs. BE-JB-17, Tab 3, at 3; AG-11).

The record indicates that post-maintenance fill and vent procedures specific to the feedwater heater do not exist (Tr. 1, at 125-127). The record is not clear on whether more general fill and vent procedures were, in fact, applied after maintenance to the heater. Nonetheless, the record indicates that the heater's water level is monitored and maintained by plant procedures three to four times a week (Exh. AG-10; Tr. 1, at 128). The record also does not support the contention that the heater will self-drain at times when the heater's water level is not being monitored and maintained by plant procedures (Exhs. AG-4; AG-5; AG-11). The Company indicated that the heater's design configuration prevents self-draining of the heater's drain cooler, since the heater's drain line is located higher than the mid-point of the drain cooler, but that, due to the physical configuration and possible leakage across level and dump valves,[7] the

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[7] The heater's drain and dump valves regulate feedwater heater water level

(continued...)

heaters drain naturally (Exhs. BE-JB-17, Tab 3, at 4; AG-11). The record does not indicate that leakage across level and dump valves occurred, or provide a dimensional correlation between the location of the heater drain line, midpoint of the drain cooler, and levels recommended by Yuba. The record thus suggests that correct water levels would be automatically maintained. Furthermore, although the record demonstrates that Pilgrim experiences periods of start-up or low power operations during the performance year, the record does not indicate that low water levels existed during specific periods of start-up or low power operation (Tr. 1, at 142-143).

Therefore, the Department finds that the record does not contain enough information to indicate that low water levels existed within the E-102A feedwater heater while Pilgrim was under start-up or low power operations; a condition that would result in turbulence and flashing in the drain cooler and damage to the feedwater heater tubes. Thus, the Department finds no evidence that the Company improperly maintained heater water levels during plant start-up and low power operation.

As discussed in Section II.C.4.iv below, if the Company and/or its contractor have failed to identify conclusively a root cause of the problem of high complexity, the Company still has an obligation to prove that it and/or its contractor have made reasonable and prudent efforts to investigate the problem, and that their failure to identify conclusively a root cause of the problem is not unreasonable. See Boston Edison Company, D.P.U. 94-1A-1 (1995), at 46-47. The Department finds that, although the Company did not identify conclusively the root cause of the tube failures, the Company has sustained its burden to demonstrate that it made reasonable or prudent efforts to identify conclusively the root cause of the tube failures given the time constraints at the time of the November 1993 outage and again during the October 1994 outage.

(...continued)
(Exh. DPU-2, at 7).

The Department thus finds no evidence to indicate that the failure of the E-102A feedwater heater tubes and the resultant shutdown of Pilgrim on November 5, 1993, was the result of unreasonable or imprudent activity by the Company. The Department also hereby places the Company on notice that the Department will review the results of the Company's planned inspection of the feedwater heater during Pilgrim's Refueling Outage Number 10, which was scheduled for March 1995 (Exhs. BE-JB-1, at 21; BE-JB-17, Tab 7, at 12).

c. The Extension to the November 5, 1993 Forced Outage

i. Background

Following Pilgrim's November 5, 1993 outage and during subsequent plant start-up, erroneous reactor vessel water level indications were received in the control room from non-safety-related feedwater level control instruments (Exh. BE-JB-1, at 21; RR-AG-2, at 2). Although erroneous readings had previously occurred in safety-related feedwater level control instruments, this was the first time erroneous readings occurred in non-safety-related feedwater level control instruments (RR-AG-2, at 3, 8). As operations personnel were controlling reactor vessel water level during start-up, the non-safety-related instruments indicated increasing water level while the water level was actually decreasing (Exhs. BE-JB-1, at 21, 22; BE-JB-17, Tab 4, at 9; BE-JB-17, Tab 5; RR-AG-2, at 2, 4, 6, 7). An automatic trip of the reactor resulted from the water level reaching the reactor's low water level trip point, which delayed Pilgrim's return to service by about 10 hours after the feedwater heater leak repairs (Exhs. BE-JB-1, at 21, 22; BE-JB-17, Tab 5). Pilgrim was returned to service on November 9, 1993 (id.).

Both safety-related and non-safety-related feedwater level control instruments at Pilgrim provide indications of reactor vessel water level (RR-AG-2, at 2-4). The instruments indicate reactor vessel water level by receiving electronic signals, which represent differential water pressures in reactor vessel water level reference lines (RR-AG-2, at 3). The reactor vessel water level reference lines are essentially vertical pipes that are connected to the reactor vessel via four condensing chambers (Exh. BE-JB-17, Tab 4, at 9; RR-AG-2, at 3). The reactor vessel water level reference lines are either filled with water by the condensing chambers as the reactor pressurizes or emptied of water by the condensing chambers as the reactor depressurizes (id.). The electronic signals received at the non-safety-related Feedwater Narrow Range Indicators and non-safety-related Reactor Vessel Level Recorder are derived from condensing chambers 13A and 13B (RR-AG-2, at 3, 4, 7). The non-safety-related Feedwater Narrow Range Indicators provide instantaneous reactor vessel level indications, while the non-safety-related Reactor Vessel Level Recorder records reactor vessel level on a chart recorder which provides both instantaneous and trend information (Exh. BE-JB-17, Tab 4, at 8; RR-AG-2, at 3, 4, 7). The non-safety-related Feedwater Narrow Range Indicators and the non-safety-related Reactor Vessel Level Recorder are located on panel C905 in Pilgrim's main control room (Exh. BE-JB-17, Tab 4, at 8).

The electronic signals received at the safety-related Reactor Vessel Narrow Range Indicators and safety-related Reactor Vessel Level Recorders are derived from condensing chambers 12A and 12B (id.). The safety-related Reactor Vessel Narrow Range Indicators provide instantaneous reactor level indications and are also located on panel C905 in Pilgrim's main control room (Exh. BE-JB-17, Tab 4, at 8; RR-AG-2, at 3, 4, 7). The safety-related Reactor Vessel Level Recorders are located on panels C170 and C171, which are 20 feet away from panel C905 (RR-AG-2, at 4). The electronic signals derived from condensing chambers 12A and 12B also perform control and reactor trip functions, thus they are designated as "safety related" (Exh. BE-JB-1, at 22; RR-AG-2, at 3, 4, 6; Tr. 1, at 120).

The erroneous indications experienced during plant start-up were caused by the gradual build-up of non-condensable gases in the reference lines associated with condensing chambers 13A and 13B (Exhs. BE-JB-1, at 22; BE-JB-17, Tab 4, at 9; RR-AG-2, at 3, 6; Tr. 1, at 119). Non-condensable gases originate from the reactor vessel water when the reactor vessel is pressurized (id.). During a reactor vessel depressurization, e.g., during a plant shut-down, the non-condensable gases expand and displace the water in the reference lines causing the water level in the reference lines to increase and feedwater level control instruments associated with the reference lines to "spike," that is, the instruments' water level indications surge as the non-condensable gases expand (Exhs. BE-JB-1, at 22; BE-JB-17, Tab 4, at 9; Tr. 1, at 119; RR-AG-2, at 3). During a subsequent reactor vessel pressurization, e.g., during a plant start-up, feedwater level control instruments associated with the reference lines indicate inaccurate high reactor vessel feedwater levels due to the built-up non-condensable gases and the inability of the reactor vessel to sufficiently refill the associated reference lines with water and compress the gases (Exh. BE-JB-17, Tab 4, at 9).

In 1993, the Company initiated a plant design change which installed a continuous leg backfill system (RR-AG-2, at 3). The continuous leg backfill system affected safety-related instrumentation by backfilling the reference lines associated with condensing chambers 12A and 12B, which initiate control and reactor trip functions, with water to remove built-up non-condensable gases and restore water volume to the reference lines (Exh. BE-JB-17, Tab 4, at 9; RR-AG-2, at 3, 4; Tr. 1, at 120). The plant design change did not include reference lines associated with condensing chambers 13A and 13B because there are no control and reactor trip functions initiated by these reference lines (RR-AG-2, at 3, 4, 6).

During the November 5, 1993 plant shut-down, spiking affected the reactor water level instruments and was detected by the Emergency Plant Information Computer ("EPIC") but not by the plant operator (id. at 6). Following the November 5, 1993 plant shut-down and during subsequent plant start-up, the control room operator stationed at panel C905 was using panel C905's non-safety-related Reactor Vessel Level Recorder to monitor reactor vessel water level while operations personnel were using the Reactor Water Cleanup System to control reactor vessel water level (id. at 2, 4, 6, 7). While operations personnel were controlling reactor vessel water level, panel C905's safety-related Reactor Vessel Narrow Range Indicator indicated decreasing water level each of the six times operations personnel discharged reactor water to the main condenser to control reactor water level (id. at 4, 7). The Company explained that, as the reactor pressure increased during the plant start-up, the non-condensable gases in the reference lines caused inaccurate indications of increasing water level on the non-safety-related Reactor Vessel Level Recorder and non-safety-related Feedwater Narrow Range Indicators (Exh. BE-JB-1, at 22; RR-AG-2, at 3, 7). While the erroneous readings indicated that the reactor water level was increasing, the reactor water level was actually decreasing as was accurately indicated by safety-related instruments associated with condensing chambers 12A and 12B (Exh. BE-JB-1, at 21; RR-AG-2, at 7). The control room operator stationed at panel C905 did not recognize that the non-safety-related Reactor Vessel Level Recorder indicated increasing water level while the safety-related Reactor Vessel Narrow Range Indicator indicated decreasing water level, and when the water level reached the low water level trip point, the reactor automatically tripped (Exhs. BE-JB-1, at 21, 22; BE-JB-17, Tab 4, at 9; BE-JB-17, Tab 5; RR-AG-2, at 2, 4, 6, 7).

ii. Attorney General's Position

The Attorney General maintains that the major cause of the November 8, 1993 reactor trip is attributable to an error by a licensed operator that was within the Company's control (Attorney General Brief at 11, 12; Attorney General Brief, citing Tr. 1, at 75, 76; Attorney General Reply Brief at 4). The Attorney General also maintains that the Company acknowledges the fact that the reactor trip was due to licensed operator error, and that the reactor trip resulted in over a 10 hour extension to the critical path (Attorney General Brief at 11, citing RR-AG-2, at 2; Attorney General Reply Brief at 4). The Attorney General concludes that the operator's error was imprudent, and that the Company should not be allowed to recover the replacement power costs associated with the entire 10 hour extension of the November 5, 1993 outage at Pilgrim (Attorney General Reply Brief at 4, 5).

iii. Company's Position

The Company argues that there is no justification for any disallowance of replacement power costs associated with the reactor trip on November 8, 1993 (Company Reply Brief at 5). The Company maintains that, although erroneous readings had previously occurred in safety-related level instruments, previous erroneous readings had not occurred in the non-safety-related level instruments that were monitored by plant operators (Company Brief at 21). The Company further maintains that the previous erroneous readings that had occurred in safety-related level instruments had been preceded by spiking of the safety-related level instruments during plant shutdown, whereas, no spiking had occurred in the non-safety-related level instruments during the November 5, 1993 plant shutdown (id. at 21). In addition, the Company maintains that industry experience has shown that the build-up of non-condensable gases in the reference lines typically takes at least 58 days of continuous plant operation (id. at 21). Furthermore, the Company maintains that, although the operator did make an error that contributed to the reactor trip, the operator's error was not a direct cause of the reactor trip (Company Reply Brief at 3, 4). The Company concludes that, because it was aware that erroneous readings in non-safety-related level instruments had never before occurred, because no spiking had occurred with the non-safety-related level instruments during the November 5, 1993 plant shutdown, and because the plant had been in operation for only 58 days prior to the event, the control room operator could not have anticipated, and therefore recognized, the erroneous reactor water level indications from the non-safety-related level instruments in time to prevent the reactor trip on November 8, 1993 (Company Brief at 21).

Finally, the Company maintains that there were some activities that were performed during the extension to the outage that had to be performed regardless of whether the reactor trip occurred and that other activities that had to be repeated as a result of the reactor trip only contributed about three hours to the extension of the outage (id. at 22, citing Tr. 1, at 116). Therefore, the Company maintains that the reactor trip only resulted in a three hour extension to the critical path of the November 5, 1993 outage (id. at 22, citing Tr. 1, at 116; Company Reply Brief at 4).

iv. Analysis and Findings

The record demonstrates that the Company was aware that during plant shutdowns erroneous readings had previously occurred in safety-related reactor water level instruments due to the build-up of non-condensable gases in reference lines related to condensing chambers 12A and 12B (RR-AG-2, at 3). This condition was corrected for safety-related instruments by a plant design change (id.). However, no such design change had been implemented for the non-safety-related feedwater level control instruments related to condensing chambers 13A and 13B (id.).

The Company should have recognized safety and operational implications and the need for accurate readings of water levels during plant start-up. The Department finds that the Company failed to recognize the importance of using reliable instruments during a plant start-up, but rather chose to rely on non-safety-related instruments, which were known to have been at risk for erroneous readings (RR-AG-2, at 3, 4, 6, 7). More specifically, the Company's operator failed to recognize the importance of utilizing the safety-related Reactor Vessel Level Indicators and Recorders during a plant start-up. The Department finds that, had the operator utilized the safety-related Reactor Vessel Level Indicators and Recorders during the plant start-up, improper water levels could have been noted and corrective action taken to prevent the November 8, 1993 reactor trip. The Department therefore finds that the operator should have anticipated the trip and that the operator's error was a direct cause and a major factor of the reactor trip.

The record establishes that activities that had to be repeated as a result of the reactor trip contributed over 10 hours to the extension of the outage. The record demonstrates that the activities that were performed during the extension, that is, "valve lineups" and "surveillances," were necessary and had been performed as the feedwater heater was being repaired and returned to service (Exh. BE-JB-1, at 21; Tr. 1, at 115, 116). The record also demonstrates that the extension did not occur while the feedwater heater was being repaired and returned to service, but occurred immediately after the feedwater heater was returned to service (Exh. BE-JB-17, Tab 5). Therefore, the Department finds that the activities that were performed during the extension were necessary activities that were being repeated, and that the activities would not have been repeated absent the extension. The Department thus finds that the reactor trip contributed over 10 hours to the extension of the outage.

The Department orders the Company to refund to ratepayers the replacement power costs associated with the 10 hour extension to the November 5, 1993 outage at Pilgrim, with interest.

d. The February 23, 1994 Forced Outage

i. Background

(A) The Main Steam Isolation Valve ("MSIV")

There are four steam lines through which steam is supplied from the reactor to the turbine at Pilgrim (Exh. BE-JB-1, at 25). Each steam line is provided with two normally open MSIVs, an in-board MSIV and an out-board MSIV, located inside and outside the primary containment, respectively (id.).[8] Under certain abnormal conditions, such as accidental reduction of pressure in the reactor, or damage of fuel, as well as during surveillance tests performed as part of the Company's preventive maintenance program, the MSIVs are closed automatically, or manually (Tr. 1, at 41). According to the Pilgrim Technical Specifications ("TS"), the MSIVs are required to operate (close) within a strictly prescribed time upon receipt of a control signal from the plant main control room (Exh. BE-JB-1, at 26; Tr. 1, at 40). The MSIVs should close fast enough to isolate the primary containment to prevent any potential release of the radioactive material, but not too fast, which could result in an unacceptably high pressure steam wave pulsing back to the reactor and causing a power spike (Exh. BE-JB-1, at 26; Tr. 1, at 39-41).

On February 17, 1994, the Company performed a routine surveillance test on an in-board MSIV (Exh. BE-JB-1, at 23). The purpose of the test was to verify that the MSIV operating time was within the limits prescribed by the TS and to establish the operability of the MSIV (Tr. 1, at 41). During the test, the MSIV failed to close and, because the valve and its control parts were located inside the primary containment, it could not be inspected and repaired while the power

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8 The primary containment is a structure that includes the reactor vessel encased within a leak-tight steel enclosure shielded with over 50 inches of concrete (Exh. BE-JB-4, at 4).

plant was operating (Exh. BE-JB-1, at 23-24). The MSIV was declared inoperable and, in compliance with the TS requirements, the corresponding steam line was shut down by closing the out-board MSIV installed in series with the failed valve (id.).

From February 17, 1994 to February 23, 1994, Pilgrim operated with the reactor power output reduced to 75 percent of its normal level, because only three of the four steam lines to the turbine were available for operation (id.). On February 23, 1994, Pilgrim was shut down to address the problem with the faulty MSIV (id. at 24-25).

Upon investigation, the Company discovered deposits of a foreign material inside the four-way valve, which is a part of the MSIV pneumatic control system (id. at 27; Tr. 1, at 42).[9] The Company concluded that the deposits found in the four-way valve were the most probable root cause of the MSIV's failure (Tr. 1, at 50). The Company explained that the deposits could have caused the piston inside the four-way valve to stick, preventing it from moving into a proper position (Exh. BE-JB-1, at 27). This, in turn, resulted in an improper control of the pneumatic pressure applied to the MSIV, which failed to close during the surveillance test on February 17, 1994 (id.).

According to the Company, the four-way valve body and some of its internal parts, such as the pistons, are made of aluminum (Exh. BE-JB-18, Tab. 6, at 5; Tr. 2, at 25-26). The Company also explained that the foreign material found in the valve was a moist white crystalline radioactive substance (Exh. BE-JB-18, Tab. 5, at 23; Tab. 6, at 5; Tr. 2, at 25-28). Based on the composition of the valve and the appearance of the deposits, the Company concluded that the material of the deposits most likely was aluminum oxide (Exhs. BE-JB-1, at 28; BE-JB-18,

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[9] The four-way valve is designed to control the position of the MSIV by changing pneumatic pressure of the gas (air or nitrogen) applied to the MSIV (Tr. 2, at 5). The operation of the four-way valve is remotely controlled from the plant's main control room (Exh. BE-JB-1, at 25; Tr. 1, at 49).

Tab. 6, at 5; AG-20; Tr. 1, at 43-45; Tr. 2, at 27-28).[10] The Company was unable to determine conclusively the source of the aluminum oxide found in the four-way valve (Exh. BE-JB-1, at 28). Based on the evidence of some rusting found on the carbon-steel components of the four-way valve and the moist condition of the deposits, the Company concluded that the aluminum oxide could have developed through the chemical reaction between moisture and the aluminum parts of the valve (Exh. BE-JB-18, Tab. 5, at 23; Tr. 1, at 43-44, 53; Tr. 2, at 29).

No specific source of the moisture inside the four-way valve was identified by the Company (Exhs. BE-JB-1, at 28; BE-JB-18, Tab. 5, at 23; AG-21; Tr. 1, at 53). However, the Company postulated that the moisture either could have generated from the condensation of the water vapors contained in the air or nitrogen circulating inside the pneumatic system, or could have entered the system through the valve's air exhaust port, which opens to the primary containment atmosphere when the MSIV is in the closed position (Exhs. BE-JB-1, at 28; BE-JB-18, Tab. 5, at 23; Tr. 2, at 15, 46-47).

Normally, the in-board MSIV and its control system, including the four-way valve, operate in a nitrogen environment (Tr. 1, at 52; Tr. 2, at 4-5). The nitrogen atmosphere inside the primary containment is produced by means of expansion of liquid nitrogen and should be of very high quality containing no moisture (Exh. BE-JB-18, Tab. 8, at 10). Therefore, according to Mr. Bellefeuille, it is unlikely that the moisture entered the valve through contaminated nitrogen (Tr. 1, at 53).

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10 At the hearings, the Company's witness, Mr. Bellefeuille, explained that the Company was not able to perform a chemical analysis of the deposits because the amount of the material found was not sufficient for analysis (Tr. 2, at 16, 33-34). In addition, according to Mr. Bellefeuille, the deposits were radioactive and could not be easily shipped off site for evaluation (id.).

Prior to every planned refueling or mid-cycle outage, the Company replaces the nitrogen inside the primary containment with air, to permit inspection and repair activities by Company personnel (id. at 54-55; Tr. 2, at 14-15). The Company explained that the air used to replace nitrogen in the primary containment is filtered and dried to meet specific dew-point specifications (Tr. 1, at 55).[11] According to the Company, it has monitored the dew point of the air in its plant air system and maintained its level low enough to avoid condensation of moisture on the equipment (Tr. 2, at 46).

Before February 1994, in one instance, the Company had observed aluminum oxide deposits in another four-way valve at Pilgrim (Exh. BE-JB-18, Tab. 6, at 4). These aluminum oxide deposits were discovered in the piston area of one of the four-way valves in February 1989, during a preventive maintenance inspection of all eight four-way valves (Exh. DPU-11; Tr. 2, at 30-31). That inspection was initiated after one of the MSIVs had failed to operate within the time prescribed by the TS (Exh. DPU-11). In February 1989, the Company attributed the MSIV's failure to operate properly to a moist black greasy material found in the corresponding four-way valve (id.). The subsequent inspection of all other four-way valves revealed the same material, though in minor quantities, in one of the remaining seven valves, along with the aluminum oxide deposits (id.; Tr. 2, at 36).

The Company was unable to conclusively determine the source of the moist foreign material found in the four-way valves in February 1989 (Exh. DPU-11(a) at 2). In February 1989, the Company focused its investigation on the possible sources of the black greasy material rather than

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[11] The dew-point specifications control the humidity of the air. The dew point is the temperature at which condensation of water vapor contained in the air begins such that water droplets would appear on the surface of equipment. Because water vapor is always present in the air, its condensation can be avoided by means of lowering the dew point of the air below the lowest possible temperature of the equipment (Tr. 2, at 46). Dryer air has a lower dew point.

on the aluminum oxide deposits found in one of the four-way valves, because, at that time, the aluminum oxide deposits did not affect the operability of the valve; the single valve in which the aluminum oxide deposits were found did not malfunction (Tr. 2, at 35-36, 38-39).

According to the Company, historically, the MSIVs had been inspected at least once every eight years as recommended by Atwood & Morrill Company, the vendor of the MSIVs (Exhs. BE-JB-1, at 29; DPU-11; Tr. 1, at 50; Tr. 2, at 8-9). In June 1989, the Company issued an office memorandum, in which it established a preventive maintenance and inspection program for the four-way valves (Exh. DPU-11, at 8-9). According to that program, all eight four-way valves were scheduled for inspection during the following eighth refueling outage ("RFO") at Pilgrim, RFO-8.[12] However, on June 7, 1991, while RFO-8 was in progress, another office memorandum was issued, in which the originally planned scope of the four-way valve inspection was limited to a sample of only two valves (Exh. DPU-11, at 13). The Company selected for inspection the two four-way valves in which the black greasy material was found in February 1989, under the assumption that a common mode of the foreign material entering the four-way valves was unlikely (Exh. DPU-11, at 13-15; Tr. 2, at 42-43). After the inspection was performed during RFO-8, and no foreign material in the four-way valves was found, the Company did not inspect the four-way valves again until February 23, 1994 (Tr. 2, at 42).[13] The four-way valve that failed on February 23, 1994 was inspected in December 1981, in April 1986, and in February 1989, and in no instance was any foreign material found (Exhs. BE-JB-18, Tab. 5, at 21; DPU-9). However, during the February 1989 inspection, the valve was not inspected in the area

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12 RFO-8, which commenced on May 4, 1991 and lasted for 105 days, was addressed by the Department in Boston Edison Company, D.P.U. 92-1A-A at 11-27 (1993).

13 Between August 1991 and February 1994, Pilgrim experienced two planned outages: a refueling outage RFO-9 and the ninth mid-cycle outage ("MCO"), MCO-9. See Boston Edison Company, D.P.U. 94-1A-1, at 10 (1995).

in which the aluminum oxide deposits were discovered in another similar valve at that time (Exhs. BE-JB-18, Tab. 5, at 21; DPU-11).

(B) The Motor-Operated Valve

During the February 23, 1994 forced outage, the Company repaired a leak in the feedwater system that was identified prior to the shutdown of the plant (Exh. BE-JB-1, at 29). In order to facilitate the leak repairs, the motor-operated ("MO") valve MO-3479 of the feedwater system was closed to isolate the faulty section of the system (id.).[14] On February 26, 1994, after the leak repairs were completed and the feedwater system was being returned to service, the MO-3479 valve failed to open (id.).

The Company determined that the MO-3479 valve did not respond to the signal to open because the valve disc casting had fractured and the valve stem had separated from the valve disc (id.).[15] Further investigation by the Company showed that the primary root cause of the separation of the stem from the disc was porosity of the disc casting, in particular, its most highly stressed section (Exhs. DPU-12(c), DPU-15(c); Tr. 2, at 52-53). According to the Company, the valve torque setting point selected within the acceptable design range but near its maximum level was a contributing factor in the February 26, 1994 incident (Exhs. BE-JB-18, Tab. 14, at 1; DPU-12; Tr. 1, at 59; Tr. 2, at 54-55).[16] The Company explained that the porosity of the valve disc had reduced its ability to sustain the thrust corresponding to the increased torque setting

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14 A number of normally open MO valves are installed along the feedwater system to facilitate maintenance and inspection of the system (Exh. BE-JB-1, at 30).

15 The stem and the disc, essential internal components of the valve, normally are mechanically connected, so that withdrawal of the stem by the motor operator results in lifting of the disc and opening of the valve (Exhs. BE-JB-1, at 30; BE-JB-18, Tab. 15, at 26-27; DPU-15).

16 The torque setting controls the thrust applied to the valve disc during normal operation (Exh. BE-JB-1, at 31; Tr. 1, at 56).

point and fractured at the weakest and most highly stressed area (Exhs. BE-JB-1, at 31; BE-JB-18, Tab. 12, at 4; Tr. 1, at 61-62).

The MO-3479 valve was manufactured in 1969, and has been in operation at Pilgrim since 1972 (Exh. AG-24; Tr. 2, at 52). According to Mr. Bellefeuille, the torque setting point of the MO-3479 valve had been increased over the last ten years to reduce leakage across the valve (Exh. BE-JB-1, at 31; Tr. 1, at 62; Tr. 2, at 52).

The requirements for the physical and other properties of the MO-3479 valve disc material were specified in accordance with the appropriate American Society for Testing and Materials ("ASTM") standard (Exh. AG-29; RR-DPU-3). Massachusetts Materials Research, Inc. ("MMR") tested a piece of the fractured disc and determined that the disc material did not meet the ASTM standard specifications, supporting the Company's own conclusion that the porosity of the disc material had reduced its strength (Exhs. BE-JB-18, Tab. 12, at 1, 4, 6, 8; Tab. 16, at 2, 4; AG-30; Tr. 1, at 63-64).

The Company Materials and Component Engineering Division visually examined the fractured components of the MO-3479 valve and concluded that, prior to the failure, only a volumetric examination of the valve disc could have revealed its internal porosity and susceptibility to failure (Exh. BE-JB-18, Tab. 12, at 7-8). The Company explained that the volumetric examination is a non-destructive test method, such as radiographic, ultrasonic, or sonic test, which reveals information about the internal condition of the material (Exh. DPU-14). According to the Company, volumetric examination is only performed when a component is classified as nuclear-safety-related (id.). The MO-3479 valve was not a nuclear-safety-related component and, therefore, the quality assurance industry standards designed for nuclear-safety-related components were not applicable to this valve when it was specified, ordered, manufactured, and inspected (Exh. DPU-14; RR-DPU-4; Tr. 2, at 56). According to the records of Powell Valve Company ("Powell"), the manufacturer of the valve, before the MO-3479 valve failed at Pilgrim, there had been only one other instance in 30 years in which a disc of a similar non-safety-related valve failed (Exh. BE-JB-18, Tab. 12, at 2; Tr. 2, at 62).

The Company's activities addressing the problem with the MO-3479 valve were on the critical path of the February 23, 1994 forced outage from February 27, 1994 to March 3, 1994 (Exh. BE-JB-18, Tab. 3, at 1; AG-22). On March 4, 1994, after all necessary preparations for start-up of the plant were completed, Pilgrim returned back on-line (Exh. BE-JB-1, at 33).

ii. Attorney General's Position

The Attorney General asserts that the February 23, 1994 forced outage and associated replacement power costs were a direct result of the Company's and its contractor's imprudent actions (Attorney General Brief at 13). The Attorney General argues that the Company should be responsible for the imprudent actions that caused both the MSIV control system problem and the problem with the MO-3479 valve (id.).

The Attorney General contends that the Company imprudently failed to monitor the humidity of the air that replaced nitrogen in the primary containment during planned outages of the plant (id. at 14). The Attorney General asserts that the air did not meet the dew-point specifications, which resulted in the intrusion of water inside the four-way valve and origination of the aluminum oxide deposits (id.). The Attorney General maintains that BECo's previous experience in 1989 should have prompted the Company to exercise better care to ensure that the air met the dew-point specifications (id. at 15).

The Attorney General also contends that BECo should be responsible for the replacement power costs that resulted from the imprudent actions of Powell, which manufactured and provided the MO-3479 valve with the abnormally porous disk that did not meet the ASTM standard (id.). The Attorney General maintains that the original deficiency of the MO-3479 valve resulted in its failure and caused an extension to the February 23, 1994 forced outage (id.).

iii. Company's Position

The Company argues that there is no basis for the disallowance of replacement power costs associated with the February 23, 1994 forced outage (Company Reply Brief at 6). The Company contends that no evidence supports the conclusion that it did not maintain a proper level of humidity of the air in the MSIV control system (id. at 5). The Company argues that it monitored the water content of the air in the MSIV control system and confirmed that it always met the dew-point specifications (id.; Company Brief at 23, citing Tr. 1, at 55, and Tr. 2, at 46).

The Company submits that the most likely source of the moisture inside the four-way valve was atmosphere in the primary containment (Company Brief at 23, citing Exh. BE-JB-18, Tab. 5, at 28; Tr. 2, at 15, 46, 47). The Company postulates that the moisture contained in the primary containment atmosphere could have entered the four-way valve through the valve's air exhaust port that is open to the containment atmospheric environment (id., citing Tr. 2, at 15, 46, 47; Company Reply Brief at 5). The Company disagrees that it had ever experienced a similar problem before February 1994 (Company Brief at 23). The Company notes that the aluminum oxide deposits found in 1989 did not affect the operability of the valve (id.). The Company claims that no evidence supports the conclusion that, prior to the February 1984 incident, the Company knew or should have known that the aluminum oxide deposits might have built-up and caused an MSIV malfunction (id. at 25; Company Reply Brief at 5).

The Company also asserts that the failure of the MO-3479 valve was unforeseeable and that the actions of BECo and Powell, the vendor and manufacturer of the valve, were reasonable and prudent (Company Brief at 25). The Company notes that the MO-3479 valve was ordered, manufactured and tested in accordance with standard industry practice for non-safety-related valves (id. at 25-26). The Company also contends that the porosity could not be detected through the normal testing performed in accordance with standard industry practice for a non-safety-related valve (id. at 26). The Company notes that Powell followed the same practices that resulted in only one or two failures in 30 years of these valves' operation in the industry (id. at 27; Company Reply Brief at 6).

iv. Analysis and Findings

(A) The Main Steam Isolation Valve

The record is clear that the February 23, 1994 forced outage was initiated to address the inoperability of the MSIV. The Company determined that the deposits found in the four-way valve, which is a part of the MSIV pneumatic control system, prevented the MSIV from proper operation during the surveillance test. The Company also concluded that the material of the deposits most likely was aluminum oxide, but could not conclusively determine its source. According to the Company, the aluminum oxide could have developed through the chemical reaction between moisture that entered the four-way valve and the aluminum parts of the valve. However, no specific source of the moisture inside the four-way valve was conclusively identified by the Company.

The Department cannot agree with the Attorney General that the fact that water entered the MSIV pneumatic control system compels a finding that BECo was imprudent in failing to monitor the air water content. In fact, the record shows that the Company did monitor the dew point of the air that was filtered and dried before entering the MSIV pneumatic control system and the primary containment (Tr. 1, at 55; Tr. 2, at 46). Because the actual source of the moisture inside the MSIV pneumatic control system remains unknown, the Department finds no evidence that the moisture entered the four-way valve as a result of any specific unreasonable or imprudent action on the part of the Company. Notwithstanding, analysis of the record suggests that the February 23, 1994 forced outage could and should have been avoided.

The record shows that aluminum oxide deposits were discovered in the piston area of a four-way valve at Pilgrim for the first time in February 1989 (Exh. BE-JB-18, Tab. 6, at 4). The record also shows that in February 1989, as in February 1994, the Company did not conclusively determine the source of the deposits and the moisture inside the four-way valve. The Company explained that in February 1989, it did not focus its investigation on the possible sources of the aluminum oxide deposits because, at that time, the deposits were found in minor quantities and did not affect the operability of the valve (Exh. DPU-11; Tr. 2, at 35-36, 38-39).

The record demonstrates that as early as in 1989, the Company knew that substantial quantities of the black greasy foreign materials inside the MSIV pneumatic control system might cause a malfunction of a four-way valve and a forced shutdown of the plant, while minor quantities of the black greasy material would not affect its operability (Exh. DPU-11; Tr. 2, at 36). The record also shows that on February 17, 1994, the aluminum oxide deposits, like the black greasy material in 1989, caused the piston inside the valve to stick or to move too slowly into a proper position (Exh. BE-JB-1, at 27; Tr. 2, at 32). Based on the record, the Department finds that the mechanism of the malfunctioning of a four-way valve caused by both types of the foreign material has similar nature and that large quantities of the aluminum oxide deposits, like large quantities of the black greasy material, may cause a malfunction of a four-way valve. The Department finds that the Company realized or should have realized the critical nature of the quantity of the aluminum oxide deposits inside a four-way valve. The Department finds that BECo also knew or should have known that the only reason why the aluminum oxide deposits found in February 1989 did not result in a malfunction of the valve was that the amount of the material that had accumulated inside the valve by that time was insufficient to restrict the valve's piston movement. Therefore, the Company could not have reasonably concluded that origination of the aluminum oxides, even in minor quantities, in the piston area of the four-way valve did not pose any risk for reliable operation of the MSIV pneumatic control system and Pilgrim as a whole. The Department finds that the Company underestimated the significance of the discovery of the aluminum oxide deposits inside the four-way valve in February 1989, and that the Company was unreasonable in failing to focus its investigation on their possible sources.

The record shows that, after the moist deposits were discovered in the MSIV pneumatic control system in February 1989, the Company did not effectively pursue the further investigation of the unresolved problem.[17] During the February 1989 inspection, the piston area of the four-way valve in which the aluminum oxide deposits were discovered five years later was not even inspected, while the aluminum oxide deposits were discovered in a similar valve in 1989 precisely in the same piston area (Exhs. BE-JB-18, Tab. 5, at 21; DPU-11). Furthermore, during RFO-8, the Company cancelled its original plan that called for inspection of all eight four-way valves and

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[17] At the hearing, the Company claimed that if it does not fully understand the cause of a problem, it continues its investigation monitoring the affected equipment (Tr. 2, at 42). Obviously, with regard to the four-way valve contamination problem, this statement is not supported by the record; in fact, the record demonstrates the contrary.

limited the scope of inspection to a sample of only two valves (Exh. DPU-11, at 13). The Company did not inspect the four-way valves again until February 23, 1994, when the failure of a four-way valve resulted in a forced outage, although the Company had an opportunity to inspect them during the two planned outages RFO-9 and MCO-9 performed at Pilgrim between August 1991 and February 1994 (Tr. 2, at 42).

The Department finds that, if the Company had ascribed more significance to the discovery of the aluminum oxide deposits in the MSIV pneumatic control system in February 1989 and diligently pursued the investigation of the source of the deposits and moisture in the system, it necessarily would have inspected all components of the eight four-way valves during the February 1989 outage. In addition, the Company would have adhered to the original June 1989 preventive maintenance and inspection schedule and inspected all eight four-way valves during RFO-8 and subsequent planned outages. The Department finds that the Company's February 1989 decision not to inspect all the components of all eight four-way valves, especially those components on which the aluminum oxide deposits were discovered in one of the valves, was unreasonable. The Department also finds that the Company's June 1991 cancellation of the original June 1989 plan that called for inspection of all eight four-way valves during RFO-8 was unreasonable.[18] The Company also has presented no evidence that its decision not to inspect any of the four-way valves during RFO-9 and MCO-9 was reasonable.

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[18] In June 1991, the Company justified its decision to limit the scope of the four-way valve inspection to a sample of the two valves in which the greasy black material was found in 1989, by stating that a common mode of the greasy black material entering the four-way valves was unlikely. While it is possible that the Company's assumption was reasonable with regard to the greasy black material, the Company has produced no evidence that would suggest that the same assumption was reasonable with regard to the formation of aluminum oxide deposits.

The Department finds that, if the Company had performed the complete inspections of all eight four-way valves during the February 1989 forced outage or during the subsequent planned outages, the aluminum oxide deposits inside the four-way valve likely would have been discovered, and sufficient investigation and remedial action could have averted the February 23, 1994 forced outage. Therefore, the Department finds that the Company failed to make all reasonable or prudent efforts consistent with accepted management practices to achieve the lowest possible overall costs to its customers. The Department finds that the Company was unreasonable in failing to establish and follow a sound preventive maintenance program and inspection schedule for the MSIV pneumatic control system. As a consequence, accumulation of the aluminum oxide deposits in the four-way valve went undetected and resulted in the February 23, 1994 forced outage. The Department hereby directs the Company to calculate the incremental replacement power costs associated with the portion of the February 23, 1994 forced outage directly attributable to the failure of the MSIV pneumatic control system, and to refund them to ratepayers, with interest.

(B) The Motor-Operated Valve

According to the record, the failure of the MO-3479 valve resulted from porosity of the valve disc material, which could not sustain the thrust corresponding to the increased torque setting point of the valve. The failure of the MO-3479 valve caused a four-day extension of the February 23, 1994 forced outage.

The record shows that the valve with a porous cast disc was manufactured in 1969 (Exh. AG-24). As a non-safety-related valve, the MO-3479 valve should have met the requirements of the ASTM standard specifications (Exh. AG-29). In fact, the valve did not meet the ASTM standard specifications and this was attributed to the disc casting internal porosity (Exh. AG-30; Tr. 1, at 63-64).

The porosity was not discovered before the disc fractured during the February 23, 1994 forced outage. Only volumetric examinations could have revealed the porosity of the disc casting, but no volumetric examinations of the disc were ever performed because the valve was classified as "non-safety-related." The record shows that the ASTM standard does not prescribe volumetric examinations for non-safety-related components. Therefore, the Department finds no evidence that BECo or Powell knew or should have known that the valve disc was porous and that the valve did not meet the ASTM standard specifications.

The Department also finds no evidence that the porosity of the disc resulted from any specific unreasonable or imprudent action by Powell while the valve was being manufactured. The record demonstrates a low failure rate of the non-safety-related valves manufactured by Powell: only one or two failures of similar valves have been reported in 30 years of their application in the industry. The Department finds that, given the unique factual circumstances of this event, holding the Company responsible for an isolated event associated with the failure of a deficient valve manufactured by an independent contractor, who has achieved a low failure rate of its product, would convert the prudence standard of G.L. c. 164, § 94G into something akin to a standard of perfection. See Boston Edison Company, D.P.U. 1009-F at 6 (1982). Accordingly, the Department finds no evidence that the portion of the February 23, 1994 forced outage from February 27, 1994 to March 3, 1994, associated with the failure of the MO-3479 valve, was directly attributable to any unreasonable or imprudent action.

e. The April 22, 1994 Forced Outage

i. Background

On April 17, 1994, the Company performed a routine surveillance test of the reactor control rod insertion time (Exh. BE-JB-1, at 33).[19] The purpose of the test was to evaluate the control rod insertion time and to ensure that it was in compliance with the plant TS (Exh. BE-JB-19, Tab. 1). The results of the April 17, 1994 test showed that, although the control rod insertion time was in compliance with the TS requirements, it had increased compared to the previous testing (Exh. BE-JB-19, Tab. 18, at 10-11). The Company investigated the causes of the increased control rod insertion time and found that the slower movement of the control rods was caused by degradation of the diaphragms in the control rod hydraulic control units (Exh. BE-JB-1, at 33-34, 36).[20] On April 22, 1994, Pilgrim was shut down and all 580 diaphragms were replaced (id. at 34). On April 29, 1994, after replacement of the diaphragms and start-up preparation activities were completed, Pilgrim was returned to service (id. at 38; Exh. BE-JB-19, Tab. 2).

The diaphragms are made of a nitrile-butadiene rubber material known as BUNA-N (Exh. AG-33, at 1). In an office memorandum dated April 26, 1994, BECo provided information concerning general characteristics of BUNA-N, extracted from the General Electric ("GE") Boiling Water Reactor ("BWR") Operator's Manual for Materials and Processes, issued in September 1990, and from other sources (id.). According to this memorandum, generally, there are three different types of BUNA-N: a high-nitrile type, a medium-nitrile type, and a low-nitrile

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[19] There are 145 hydraulically controlled control rods in the reactor at Pilgrim (Exhs. BE-JB-3, at 5; BE-JB-19, Tab. 18, at 10). Rapid insertion of the control rods into the reactor core results in an immediate reactor shutdown ("scram") (id.).

[20] There are 580 diaphragms installed in the 145 control rod hydraulic control units (Exh. BE-JB-1, at 34). Degradation of the diaphragms, such as cracking, hardening, etc., may result in slower operation of the valves in the hydraulic control unit and, accordingly, slower control rod insertion into the reactor core (id. at 34-35).

type (id.). The high-nitrile type of BUNA-N is considered the best and the most appropriate type for the Pilgrim application with the longest lifetime (id.). However, as Mr. Bellefeuille explained, the superiority of the high-nitrile BUNA-N material did not mean that the Company could not use medium-nitrile BUNA-N diaphragms at Pilgrim (Tr. 1, at 67). The Company's memorandum dated April 26, 1994, categorized the low-nitrile type of BUNA-N as unsuitable for use at Pilgrim, because the diaphragms manufactured from the low-nitrile BUNA-N would not last longer than a year (Exh. AG-33, at 1). Not all manufacturers of BUNA-N specify the composition of the material, but if a buyer identifies and specifies the desired type of BUNA-N, it will be supplied (id.; Tr. 1, at 69).

Mr. Bellefeuille explained that BECo purchased the control rod hydraulic control units, including the diaphragms, from GE, which procured them from Automatic Switch Company ("ASCO") to meet BECo's specifications (Tr. 1, at 68; Tr.2, at 82).[21] Mr. Bellefeuille further explained that the level of nitrile in BUNA-N was never specified by BECo or GE in their purchase orders for the diaphragms (Tr. 1, at 69; Tr. 2, at 80). According to the Company, in compliance with the GE recommendations based on industry experience and the operating environment at Pilgrim, the diaphragms were replaced every four-and-a-half years on average (Exh. BE-JB-1, at 36; Tr. 1, at 83; Tr. 2, at 82, 111). The Company explained that, in 1991, during RFO-8, all the 580 diaphragms were replaced (Exhs. BE-JB-19, Tab. 16, at 4; BE-JB-1, at 36; Tr. 2, at 78). In October 1993, GE assured BECo that the diaphragms could be in service for approximately four years (Exh. BE-JB-19, Tab. 3, at 2; Tr. 1, at 68, 70). Based on the GE

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[21] ASCO manufactures and supplies the control rod hydraulic control units which are equipped with the diaphragms manufactured by Itran Company from chemicals supplied by Zeon Chemical Company (Exh. AG-61, at 14; Tr. 2, at 83).

recommendations, the Company scheduled the next replacement of the diaphragms for 1995 (Tr. 1, at 65, 71).

After the April 22, 1994 incident, the Company contracted with MMR to determine the root cause of the premature diaphragm degradation (Exh. BE-JB-19, Tab. 16, at 5). MMR tested samples of the degraded diaphragms and concluded that the composition of the material was consistent with the BUNA-N specifications and that nitrile content did not directly correlate with the degree of the diaphragm degradation (Exh. AG-33, at 4; Tr. 2, at 72). GE also performed its own investigation and concluded that although the variation in the composition of the sample material was within the range expected for a medium- to high-nitrile type of BUNA-N, some correlation existed between the material degradation rate and variations in the material composition (Exh. AG-33, at 10, 16). Both companies, MMR and GE, performed tests to identify the nitrile content of the samples provided by BECo (id. at 5, 10). MMR observed only slight variation in the nitrile content of the samples, while GE concluded that the variation in the nitrile content was within a 20-percent range (id. at 5, 10).[22]

Mr. Bellefeuille explained that the BUNA-N material had been used at nuclear power plants since the early 1960s, and that, prior to April 1994, the nuclear power industry had never experienced problems of premature aging of the BUNA-N diaphragms associated with the variations in the composition of the material (Exh. BE-JB-19, Tab. 12; Tr. 1, at 69; Tr. 2, at 76, 111). According to the Company, not a percentile content of nitrile nor any other single component, but rather an odd specific combination of numerous ingredients used in the process of manufacturing of BUNA-N might have resulted in earlier degradation of the material at Pilgrim

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[22] MMR tested six sample diaphragms in various stages of degradation (Exh. AG-33, at 4). The nitrile content of the samples tested by MMR varied from 22.5 percent to 39.0 percent, which shows that the test results by GE and MMR are essentially consistent (id. at 9).

(Exh. AG-61, at 7; Tr. 2, at 75). However, the root cause of the problem remains unknown, and GE continues its investigation (Exh. BE-JB-19, Tab. 12; Tr. 1, at 71; Tr. 2, at 89). In particular, Mr. Bellefeuille explained that GE is trying to better understand the correlation between the composition of BUNA-N and the material degradation rate (Tr. 2, at 75, 94).

ii. Attorney General's Position

The Attorney General contends that the diaphragm failure that led to the April 22, 1994 forced outage resulted from imprudent actions by the Company's contractor, GE, which supplied to the Company control rod hydraulic control units with the deficient diaphragms (Attorney General Brief at 18). The Attorney General maintains that GE knew or should have known that the BUNA-N material might have different composition and that the diaphragms manufactured with BUNA-N of various composition do not have the same lifetime (id.). In particular, the Attorney General claims that GE knew or should have known that high-nitrile BUNA-N was the best type for use at Pilgrim, but provided to BECo diaphragms made of various types of BUNA-N (Attorney General Reply Brief at 6). The Attorney General notes that although the manufacturers of BUNA-N do not specify the nitrile content of their product, they can be expected to comply with a buyer's specification if a particular type is requested (Attorney General Brief at 17, citing Exh. AG-33, at 1).

The Attorney General argues that, because GE made a recommendation that the diaphragms would last until 1995, it had an obligation to provide diaphragms with a composition that would assure their operation until 1995 (Attorney General Brief at 18-19). The Attorney General maintains that GE was imprudent in failing to comply with that obligation and that BECo is responsible for its contractor's imprudent action (id.). The Attorney General concludes that

BECo should refund to its ratepayers the replacement power costs associated with the April 22, 1994 forced outage (id.).

iii. Company's Position

The Company argues that there is no basis for disallowance of the replacement power costs associated with the April 22, 1994 forced outage (Company Brief at 31). The Company asserts that the April 22, 1994 forced outage did not result from imprudent actions by the Company or GE, because the premature aging of the diaphragms was unforeseeable (Company Brief at 27).

The Company claims that the diaphragm degradation discovered at Pilgrim in April 1994 was a new, previously unknown problem (id. at 29). The Company notes that the root cause of the diaphragm premature degradation is still under investigation (id.). The Company asserts that the existence of the three types of the BUNA-N material with different levels of nitrile was not commonly known prior to the April 22, 1994 forced outage (id. at 29). However, the Company maintains that the issue whether GE knew or should have known that there were different types of BUNA-N is irrelevant because, according to the Company, no correlation exists between the composition of the BUNA-N material and the diaphragm degradation (id. at 30). The Company argues that, prior to April 1994, based on the information available at that time, GE had no reason to change its representation regarding the useful life of the diaphragms (id. at 31).

iv. Analysis and Findings

The record is clear that the April 22, 1994 forced outage was initiated to replace all 580 diaphragms in the control rod hydraulic control units. The deficiency of the diaphragms was discovered after a routine surveillance test of the control rod insertion times revealed that movement of the control rods was slower than during the previous tests. The record shows that the diaphragms degraded prematurely, i.e., in less than three years, compared to four years projected by GE.

According to the record, the diaphragms were made of a nitrile-butadiene rubber material known as BUNA-N (Exh. AG-33, at 1). The record also shows that, based on the content of nitrile in the BUNA-N composition, the type of the material is classified either as high-nitrile type, medium-nitrile type, or low-nitrile type (id.). The high-nitrile type of BUNA-N is the best type for the Pilgrim application and the low-nitrile type of BUNA-N is the worst, inappropriate type (id.). The record shows that this information was derived from the GE BWR Operator's Manual for Materials and Processes, issued in September 1990 (id.). Based on the record, the Department finds that, prior to April 1994, BECo and GE knew or should have known that three different types of BUNA-N with different nitrile content existed and that low-nitrile type of BUNA-N was inappropriate for use at Pilgrim.

The record shows that BECo and GE had never specified the composition of the BUNA-N material used for manufacturing of the diaphragms for Pilgrim (Tr. 1, at 69; Tr. 2, at 80). The record also demonstrates that it is not a normal industry practice to specify the nitrile content in the BUNA-N material either by a buyer of the product, or by its manufacturer (Exh. AG-33, at 1; Tr. 1, at 70). However, the Department finds no evidence that this practice resulted in procurement of the BUNA-N diaphragms with an inappropriately low level of nitrile. In fact, GE concluded that the diaphragms were manufactured from medium- to high-nitrile BUNA-N material, rather than from inappropriate low-nitrile type of BUNA-N (Exh. AG-33, at 10). The Department finds no evidence that would suggest that medium-nitrile type of BUNA-N should not be used at Pilgrim.

Moreover, the Department finds no evidence that the premature degradation of the diaphragms discovered in April 1994 was associated exclusively with the nitrile content of the BUNA-N material used for the manufacturing of the diaphragms. Analysis of record information suggests that some correlation still may exist between the composition and the degradation rate of the BUNA-N material (Exhs. AG-33, at 10, 16; AG-61, at 7; Tr. 2, at 75). However, this correlation may well be much more complex than a simple link between the rate of the material degradation and the content of nitrile. In addition, the record shows that it is still unclear what particular combination of the components of BUNA-N is critical for the rate of the material degradation, and why (Tr. 2, at 75, 94). According to the record, prior to April 1994, neither Pilgrim nor any other nuclear power plant had experienced problems of the premature degradation of the BUNA-N diaphragms associated with the variations in the composition of the material, even though it is possible that, given the lack of the nitrile content specifications, various nitrile types of BUNA-N were used to produce the diaphragms (Exh. BE-JB-19, Tab. 12; Tr. 1, at 69; Tr. 2, at 76, 111). Therefore, the Department finds no evidence of unreasonable actions by the Company or its contractor, GE, that caused the April 22, 1994 forced outage at Pilgrim.

2. New Boston 1

a. Introduction

New Boston 1 is a 350 MW fossil unit located at New Boston Station, Boston, Massachusetts (Exhs. BE-PANEL-3, at 2; BE-PANEL-8, at 3). The unit has been in commercial operation since 1965, and is owned and operated by the Company (id.).

During the performance year, New Boston 1 experienced one planned outage and four unplanned outages. The planned outage was necessary in order to obtain the boiler certificate in compliance with the Commonwealth of Massachusetts boiler inspection requirements

(Exh. BE-PANEL-1, at 14). The boiler certification outage was scheduled for nine days, from March 19, 1994 to March 27, 1994, but was completed one day ahead of schedule (id.). Two forced outages, during which a malfunction of the turbine control system and a problem with an auxiliary boiler feed pump were addressed, occurred on April 30, 1994 and on August 4, 1994, respectively, and lasted for approximately three days each (id. at 15, 18). The other two forced outages, from June 2, 1994 to June 16, 1994, and from June 26, 1994 to August 3, 1994, were attributed to a fluid drive vibration problem (id. at 16-17).

No issues related to the March 19, 1994 boiler certification outage or to the April 30, 1994 and August 4, 1994 forced outages at New Boston 1 were addressed by the Attorney General on brief. The Department finds no evidence of unreasonable actions in connection with the March 19, 1994 planned outage and the April 30, 1994 and the August 4, 1994 forced outages at New Boston 1.

The Attorney General addressed on brief two forced outages that occurred on June 2, 1994, and on June 26, 1994, which resulted from a fluid drive unit vibration problem (Attorney General Brief at 19). A discussion of the June 2, 1994 and the June 26, 1994 forced outages follows. The following section also incorporates the analysis of the Company's investigation of the series of forced outages, from May 30, 1993 to July 8, 1993, caused by the failure of the turbine extension shaft, because, as discussed infra, it is possible that the turbine extension shaft problems experienced in 1993 might be related to the fluid drive unit problems experienced in 1994.[23]

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[23] In Boston Edison Company, D.P.U. 94-1A-1, at 48, 62, the Department ordered the Company to continue its investigation of the turbine extension shaft problems experienced between May 30, 1993 and July 8, 1993, and to report its findings in the next performance (continued...)

b. The Failures of the Fluid Drive Unit and the Turbine Extension Shaft

i. Background

(A) The June 2, 1994 and the June 26, 1994 Forced Outages

On June 2, 1994, while the Company was performing start-up activities at New Boston 1 after four weeks of reserve status, the unit tripped due to high vibrations in the fluid drive unit (Exh. BE-PANEL-1, at 16). The fluid drive unit is essentially an oil-filled automatic transmission, whose purpose is to control the speed of the boiler feed pump (Tr. 3, at 35-36).[24] The input shaft of the fluid drive unit is coupled with the high-pressure turbine extension shaft, and the output shaft drives the boiler feed pump (Exh. BE-PANEL-13, at 6). During normal operation, the input shaft of the fluid drive unit spins at a constant synchronous speed, which is 3600 revolutions per minute ("RPM"), and the speed of the output shaft of the fluid drive unit may vary in a wide range with a maximum limit of
3,510 RPM (id.).

During the June 2, 1994 forced outage, the Company inspected the fluid drive unit and found that the inboard bearing of the input shaft of the fluid drive unit and its input and output shafts were damaged (Exhs. BE-PANEL-1, at 17; BE-PANEL-13, at 12; AG-38). On June 16, 1994, after BECo had replaced the fluid drive unit bearings and made other necessary repairs to the fluid drive unit input and output shafts, the unit was returned to service (Exhs. BE-PANEL-1, at 17; BE-PANEL-13, at 12; AG-38).

[23](...continued)
review filing.

[24] The design and operation of the fluid drive unit and the turbine extension shaft at New Boston 1 were described in detail in Boston Edison Company, D.P.U. 94-1A-1, at 43.

During the outage, the Company also installed vibration probes on the fluid drive unit components to continuously monitor vibration (Exh. BE-PANEL-13, at 12). The Company explained that, at that time, the root cause of the problem was unclear and accumulating vibration data was required for analysis and determination of the root cause (Tr. 3, at 13). The Company believed that the vibration could be reduced by balancing the fluid drive unit shafts, but this procedure could be implemented only during a shutdown of the plant (Exh. AG-39). After June 16, 1994, and until June 26, 1994, New Boston 1 operated with a maximum output restricted to 200 MW to minimize vibration of the fluid drive unit (Exhs. BE-PANEL-13, at 12; DPU-23). According to the Company, this restriction was established based on vibration data that the Company had obtained by June 16, 1994 (Exh. DPU-24).

On June 26, 1994, the unit was shut down because a fluid drive unit oil pipe had failed (Exh. BE-PANEL-1, at 17). The Company inspected the fluid drive unit internal components and once again discovered fluid drive unit bearing damage (Exh. BE-PANEL-1, at 17). The Company determined that the most likely mechanism of the fluid drive unit oil pipe failure was fatigue (Exh. BE-PANEL-1, at 17).

During the June 26, 1994 forced outage, the fluid drive unit was overhauled by its manufacturer, Howden Sirocco Company (Exh. BE-PANEL-13, at 9; Tr. 3, at 23, 120). The Company also replaced the grout under the fluid drive unit foundation, installed additional permanent vibration probes on the fluid drive unit, and performed inspections of the turbine extension shaft and related components (Exh. BE-PANEL-13, at 9; DPU-25). On August 3, 1994, the fluid drive unit repairs were completed, and on August 6, 1994, New Boston 1 was returned to service.[25] Beginning on September 1, 1994, and through the end of the performance

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[25] From August 4, 1994 to August 6, 1994, New Boston 1 experienced another forced (continued...)

year, a restriction of New Boston 1's output was in effect, because the Company continued to observe an increased vibration on the fluid drive unit after the August 6, 1994 restart of the unit (Exh. BE-PANEL-1, at 17).

Based on the extensive root cause analysis, the Company attributed the failure of the fluid drive unit oil pipe to non-synchronous vibration (Exh. BE-PANEL-13, at 4). The Company explained that non-synchronous vibration is vibration that occurs at a non-synchronous frequency and corresponds to the unit's operation under low loads when the speed of the fluid drive unit output shaft is between 2300 RPM and 2800 RPM (Exh. BE-PANEL-13, at 6). The Company determined that turbulence in the oil inside the fluid drive unit occurs when the speed of the output shaft is between 2300 RPM and 2800 RPM (Tr. 3, at 35).[26]

Originally, New Boston 1 was purchased and dispatched as a baseload unit operating at full or near full load of 350 MW (Exh. DPU-25; Tr. 3, at 63; RR-AG-4). However, since 1989, New Boston 1's mode of operation has gradually changed because new, more efficient generating units have become available for the baseload dispatch (Tr. 3, at 64, 113). According to the Company, since 1989, the average daily load of New Boston 1 had been decreasing; by 1994 the average daily load was 225 MW (Exh. BE-PANEL-13, at 7; Tr. 3, at 64). The Company explained that

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[25](...continued)
outage caused by a problem with the unit's auxiliary boiler feed pump (see below).

[26] Random fluctuations of the oil flow local velocities and pressures make the flow turbulent. These fluctuations, in turn, may be reflected by the fluid drive unit bearings and transmitted to the fluid drive unit shaft in the form of vibration (Exh. DPU-25; Tr. 3, at 106-107).

the reduction of the average daily load of New Boston 1 resulted from its dispatch as a "cycling" unit (Exh. DPU-25; Tr. 3, at 30, 64).[27]

Operation of New Boston 1 at the reduced load required spinning of the output shaft of the fluid drive unit at a lower speed (Tr. 3, at 151-152). The Company explained that when New Boston 1's output was 220 MW or lower, the speed of the output shaft of the fluid drive unit was between 2300 RPM and 2800 RPM, i.e., exactly within the range at which turbulence occurred in the oil inside the fluid drive unit (Exh. DPU-25). Because turbulence does not occur at a speed of the fluid drive unit output shaft above 2800 RPM, New Boston 1 never experienced problems caused by high vibration of the fluid drive unit when it was dispatched as a baseload unit (id.; Exh. BE-PANEL-13, at 7; Tr. 3, at 26).

The Company attributed the non-synchronous vibration, which could not be eliminated by balancing, to the fluid drive unit shaft bearing stiffness and the turbine extension shaft steady rest bearing configuration (Exhs. DPU-25; AG-41). The Company further explained that the fluid drive unit shaft and supporting bearings were not stiff enough to sustain that turbulence, so that the bearings transmitted the turbulence in the oil to the fluid drive unit shaft, causing vibration (Exh. DPU-25; Tr. 3, at 36, 106-108).

In addition, the Company focused its investigation on design differences between New Boston 1 and New Boston 2, which never experienced similar vibration problems (Tr. 3, at 110, 146). The Company explained that design differences may have explained why vibration problems were experienced at New Boston 1 but not at New Boston 2 (id.). According to the Company, both units are approximately the same age, were originally dispatched by NEPOOL as baseload

[27] "Cycling" mode of operation means that the output of New Boston 1 continually followed the load varying in a wide range during a day, between its minimum and maximum level (Exh. DPU-25; Tr. 3, at 30).

units and, subsequently, as cycling units (id. at 146). New Boston 1 was designed by Westinghouse Electric Corporation ("Westinghouse") and New Boston 2 was designed by GE (id. at 110; RR-AG-4). The Company concluded that the design of the coupling between the turbine extension shaft and the fluid drive unit input shaft was one of the most important differences between New Boston 1 and New Boston 2 that might have explained the vibration problem at New Boston 1 (Tr. 3, at 12, 14, 110). According to the Company's witness, Mr. Flaherty, the design of the coupling of New Boston 1 was more appropriate for baseload operation and was a major factor that contributed to high vibrations when the unit was operating in a "cycling" mode (Tr. 3, at 12, 14). Mr. Flaherty further explained that, before and until the investigation was initiated, no information was available indicating that the coupling was not adequate for the "cycling" mode of operation (Tr. 3, at 146-147).

(B) Root Causes of the Series of Forced Outages from May 30, 1993 to July 8, 1993

According to the Company, its investigation continues into the possible root causes of the series of forced outages from May 30, 1993 to July 8, 1993 associated with the turbine extension shaft problems (Exh. AG-42). The Company stated that, while it is possible that the turbine extension shaft vibration problems experienced in 1993 and the fluid drive unit vibration problems experienced in 1994 are related, the actual correlation between them has not been conclusively determined (id.; Tr. 3, at 15, 26-29). The Company explained that during the 1995 major overhaul at New Boston 1 the unit would be disassembled and inspected (Exh. AG-42; Tr. 3, at 15). The Company expects to develop its final conclusions regarding the root causes of the turbine extension shaft vibration problems experienced in 1993 after the unit's 1995 major overhaul is completed (Exh. AG-42; Tr. 3, at 26).

ii. Attorney General's Position

The Attorney General contends that both the June 2, 1994 and June 26, 1994 forced outages resulted from imprudent actions by BECo or its contractor, Westinghouse (Attorney General Brief at 24). The Attorney General challenges the Company's statement that New Boston 1 and its components were designed for baseload operation and not for operation in the "cycling" mode (id. at 23). The Attorney General maintains that BECo failed to sustain its burden of proof because no evidence was presented that the unit and its components were designed for baseload operation and not for "cycling" operation, while the record shows that the vibration problems were associated with the "cycling" operation of New Boston 1 (id. at 23-25).

The Attorney General further argues that if New Boston 1 and its components, including the coupling between the turbine and the fluid drive unit, were indeed designed for baseload operations, Westinghouse, the designer of the unit, should have advised BECo of the design restrictions when New Boston 1 started to operate as a "cycling" unit in 1989 (id. at 24). The Attorney General asserts that under this scenario, the fluid drive unit problems are attributable to Westinghouse's imprudence in failing to disclose to BECo that the coupling was not designed for "cycling" operations (id. at 25). The Attorney General maintains that, if Westinghouse had informed BECo about the coupling design inadequacy, BECo would have replaced the coupling preventively with another design more appropriate for "cycling" operation. The Attorney General concludes that, regardless of whether the New Boston 1 was or was not designed for baseload operations, BECo should be responsible for the replacement power costs associated with the June 2, 1994 and June 26, 1994 forced outages (id.).

iii. Company's Position

The Company argues that there is no basis for a disallowance of any replacement power costs associated with the forced outages that occurred on June 2, 1994 and on June 26, 1994 (Company Brief at 37). The Company claims that no evidence supports the conclusion that either of the two forced outages resulted from unreasonable or imprudent actions by the Company or by any component vendor (id. at 36). The Company asserts that, based on the facts that the Company knew or should have known prior to the outages, the problems associated with the fluid drive unit were unanticipated and the Company's actions were reasonable and prudent (id. at 33, 36).

The Company claims that, although New Boston 1 was designed primarily for baseload operation, it was not designed to operate exclusively as a baseload unit (id. at 35; Company Reply Brief at 8). The Company asserts that a unit designed as a baseload unit is not restricted to baseload operation only, but rather is designed to operate more efficiently at full load (Company Brief at 35). The Company argues that, because New Boston 1 was not restricted to baseload operation only, Westinghouse had no reason to advise BECo regarding any potential implications of "cycling" operation of New Boston 1 (id.).

iv. Analysis and Findings

(A) Analysis of the June 1994 Forced Outages

The record shows that the forced outages that occurred on June 2, 1994 and on June 26, 1994, resulted from vibration problems originating in the fluid drive unit of New Boston 1. According to the record, the vibration was caused by operation of the unit in the "cycling" mode, i.e., with the variations of the output of the unit in a wide range between its minimum and maximum level during a day. Operation of New Boston 1 under loads below 220 MW was associated with fluid drive unit output shaft speeds of between 2300 RPM and 2800 RPM, which caused turbulence in the oil inside the fluid drive unit. The record is clear that stiffness of the fluid drive unit shaft and supporting bearings was inadequate to absorb the vibration caused by the oil flow turbulence, and that the bearings transmitted the turbulence of the oil to the fluid drive unit shaft, causing vibration (Exh. DPU-25; Tr. 3, at 33-36 and 106-108). In addition, the record shows that the design of the coupling between the turbine extension shaft and the fluid drive unit input shaft was inadequate for continuous operation of the unit in the "cycling" mode and contributed to the vibration problem of the fluid drive unit (Tr. 3, at 12, 14).

According to the record, New Boston 1 was purchased as a baseload unit and operated as such from 1965 to 1989 (Tr. 3, at 63; RR-AG-4). The record is clear that, starting from 1989, New Boston 1's primary mode of operation gradually changed from the baseload type to the "cycling" type because new, more efficient generating units became available for the baseload dispatch by NEPOOL (Exh. BE-PANEL-13, at 7; Tr. 3, at 64, 113). The record shows that New Boston 1 was designed to operate primarily (but not exclusively) in the baseload mode and that no formal restrictions existed for the "cycling" mode of operation. Based on the record, the Department finds no evidence that the Company was unreasonable in operating New Boston 1 in "cycling" mode starting from 1989.

The record shows that inadequate stiffness of the fluid drive unit shaft and supporting bearings along with the implications of the coupling design, which was inadequate for the "cycling" mode of operation, had not been discovered before the Company completed its investigation of the root causes of the fluid drive unit vibration problem (Tr. 3, at 117). The Department finds no evidence that, prior to the June 1994 forced outages, the Company or Westinghouse knew or should have known that the stiffness of the structure comprised of the fluid drive unit shaft and the bearings and the design of the coupling between the turbine extension shaft and the fluid drive unit were inadequate for the "cycling" mode of operation of New Boston 1. Therefore, the Department finds no evidence of unreasonable or imprudent actions by BECo or Westinghouse that caused high vibrations of the fluid drive unit and the June 1994 forced outages.

(B) Analysis of the Root Causes of the Failure of the Turbine Extension Shaft in 1993

The record shows that the Company continues its investigation of the root causes of the series of the forced outages caused by the failure of the turbine extension shaft in 1993 (Exh. AG-42). The record also shows that the Company expects to have the final conclusions available upon the completion of the major overhaul at New Boston 1 scheduled for 1995 (Exh. AG-42; Tr. 3, at 26). The Department directs the Company to continue its investigation of this matter and to report its findings in the next performance review filing.

3. New Boston 2

a. Introduction

New Boston 2 is a 350 MW fossil unit located at New Boston Station, Boston, Massachusetts (Exhs. BE-PANEL-3, at 2; BE-PANEL-8, at 3). The unit has been in commercial operation since 1967, and is owned and operated by the Company (id.).

During the 1993-1994 performance year, New Boston 2 experienced one planned outage and seven unplanned outages (Exhs. BE-PANEL-1, at 20-26; BE-PANEL-17). The planned outage was necessary in order to inspect and overhaul the boiler (Exhs. BE-PANEL-1, at 20; BE-PANEL-59). It was scheduled to be completed in 58 days, from September 4, 1993 to November 1, 1993, and was completed on schedule (id.). Four unplanned outages of from two to four days, occurred during the performance year, during which boiler tube leaks in the furnace wall were repaired (Exh. BE-PANEL-17). The fifth unplanned outage lasted three days and occurred on May 11, 1994, during which repairs to a turbine control valve were performed (Exh. BE-PANEL-21). The sixth unplanned outage lasted a total of three days, occurred from November 7, 1993 to November 9, 1993, continued from November 13, 1993 to November 14, 1993, and addressed the failure of the generator stator liquid cooling pump bearings (Exh. BE-PANEL-18). The seventh unplanned outage lasted from June 10, 1994 to June 13, 1994, and was necessary in order to repair a steam leak at the east main steam stop valve (Exh. BE-PANEL-1, at 22, 24).

The Attorney General addressed on brief only the forced outage that began on November 7, 1993, which resulted from the failure of the generator stator liquid cooling pump bearings (Attorney General Brief at 25). The Department finds no evidence of unreasonable actions in connection with the September 4, 1993 planned outage, or the January 17, 1994, February 13, 1994, May 11, 1994, June 10, 1994, June 21, 1994, or July 22, 1994 unplanned outages at New Boston 2. A discussion of New Boston 2's forced outage that began on November 7, 1993, follows.

b. The Failures of the Generator Stator Liquid Cooling Pump Bearings

i. Background

On November 7, 1993, New Boston 2 was shut down by operators because of failures in both generator stator liquid cooling pumps ("cooling pumps") (Exh. BE-PANEL-1, at 21). The cooling pumps provide cooling water to the stationary portion of the unit's generator (Exh. BE-PANEL-18). The Company disassembled the cooling pumps and discovered that the inboard and outboard bearings within both cooling pumps had overheated and failed (Exhs. BE-PANEL-18; AG-45; Tr. 3, at 37). The inboard and outboard bearings are similarly constructed ball bearings mounted back-to-back in the cooling pumps, and are normally lubricated with oil

(Exhs. AG-45, at 3; DPU-28). The Company initially suspected that the lubricating oil's viscosity was inadequate and caused the bearings to overheat, but after inspection determined that the viscosity was acceptable (Exh. BE-PANEL-18). The Company subsequently attributed the overheated bearings to an incorrect level of lubricating oil in the cooling pumps that led to insufficient lubrication of the bearings (Exhs. BE-PANEL-1, at 21; BE-PANEL-18; DPU-28; Tr. 3, at 135, 136). The cooling pumps were removed and sent to a local repair shop of the manufacturer, the Ingersoll-Dresser-Rand Pump Company ("Ingersoll") (Exhs. BE-PANEL-1, at 21; BE-PANEL-18; Tr. 3, at 38). The local repair shop repaired the cooling pumps by replacing the failed bearings (id.). The cooling pumps were then reinstalled at New Boston 2 and the unit was returned to service on November 9, 1993 (Exh. BE-PANEL-1, at 21).

On November 13, 1993, New Boston 2's operation was again interrupted due to failure of the cooling pumps (Exh. BE-PANEL-1, at 21). The cooling pumps failed because their inboard and outboard bearings had again overheated and failed (Exh. BE-PANEL-1, at 21). This time the Company was convinced that the overheating of the bearings was not attributable to insufficient lubrication, because after the November 7, 1993 failure plant operators had made extra rounds specifically to monitor lubricating oil levels (Tr. 3, at 37-39, 135, 136). The cooling pumps were again removed and sent back to Ingersoll's local repair shop for repair (Tr. 3, at 38-39). The failed bearings were removed by Ingersoll and sent to two bearing manufacturers, SKF Bearing Services Company and The Torrington Company,[28] for examination and diagnosis (Exhs. BE-PANEL-18; AG-45; Tr. 3, at 49). These bearing manufacturers concluded that the bearings, which were "non-preloaded" type bearings,[29] failed

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28 The Torrington Company is a subsidiary of Ingersoll-Rand (Exh. AG-45).

(continued...)

because they had been used in an application that produced uneven loading of the balls (Exhs. BE-PANEL-1, at 22; BE-PANEL-18; AG-45). This, according to SKF Bearing Services Company, caused "random actions" of the balls that resulted in overheating (Exh. AG-45). The Torrington Company theorized that, operation of the bearings with uneven loading of the balls caused an imbalance of load distribution between the inboard and outboard bearings, which resulted in the inboard bearings carrying the majority of the load and a subsequent overheating of the inboard bearings (id.). Both bearing manufacturers recommended that the bearings be replaced with "preloaded" type bearings rather than non-preloaded type bearings, which would allow the bearings to be torqued to a higher value during installation to produce an even loading of the bearing's balls during operation (Exhs. AG-45; AG-46; Tr. 3, at 40, 41). The bearing manufacturers made this recommendation because a design change to the cooling pumps had occurred prior to the 1993 planned overhaul at New Boston 2 that had changed the mechanical loading on the cooling pumps' bearings (Exh. BE-PANEL-18). In fact, Ingersoll had recommended, as early as 1963, that preloaded type bearings should be installed in place of non-preloaded type bearings when replacing the cooling pumps' standard packing seals with mechanical seals (Tr. 3, at 43, 44, 47, 48, 138).

During the 1993 overhaul at New Boston 2, the cooling pumps were sent to Ingersoll's local repair shop for overhaul and the overhaul included removal and replacement of the cooling pumps' bearings and mechanical seals, but resulted in the removal of their preloaded bearings and the installation of non-preloaded bearings (Exhs. BE-PANEL-18;

(...continued)

[29] Preloaded type bearings allow the bearing to be torqued, or tightened, to a higher value which results in even loading of the bearing's balls (Exh. AG-46; Tr. 3, at 40, 41). Unlike a preloaded type bearing, if a non-preloaded type bearing is tightened as much as a preloaded type bearing, the bearing will seize (Tr. 3, at 51, 52).

BE-PANEL-59, Tab 4, at 18; Tr. 3, at 46-48, 53, 54, 132, 133). When the cooling pumps were sent to Ingersoll's local repair shop after their failure on November 7, 1993, non-preloaded bearings again were installed (Exh. BE-PANEL-18; Tr. 3, at 44, 45). According to the Company's witness, Mr. Carroll, because of a series of mergers between pump manufacturers, Ingersoll's parts list contained out-of-date information regarding bearings to be installed in the cooling pumps; most significantly, the local repair shop did not have an updated parts list for the cooling pumps reflecting the need for preloaded bearings (Exh. BE-PANEL-18; Tr. 3, at 44, 45). As a result, non-preloaded bearings were installed (id.). The amount of time the failure of the bearings contributed to outages at New Boston 2 totaled three days (Exh. BE-PANEL-1, at 21).

ii. Attorney General's Position

The Attorney General maintains that the cooling pumps' manufacturer installed non-preloaded bearings during the 1993 overhaul and again on November 7, 1993 (Attorney General Brief at 26). The Attorney General maintains that the installation of the non-preloaded bearings was not appropriate for the application and caused the malfunction of the cooling pumps which resulted in the November 7, 1993 forced outage at New Boston 2 (id.). Therefore, the Attorney General claims that the cooling pumps' manufacturer was imprudent in installing the non-preloaded bearings during the 1993 overhaul and again on November 7, 1993 (Attorney General Brief at 26; Attorney General Reply Brief at 8).

The Attorney General claims that the Company must be held responsible for the imprudent actions of its contractor under the Department's standard (Attorney General Brief at 3, 26). In conclusion, the Attorney General maintains that the Company should not be allowed to recover the replacement power costs associated with the forced outage at New Boston 2 that began on November 7, 1993 (Attorney General Brief at 26).

iii. Company's Position

The Company maintains that, because of a series of mergers between pump manufacturers, Ingersoll's parts list contained out-of-date information regarding bearings to be installed in the cooling pumps (Company Brief at 38). The Company admits that, as a result, non-preloaded type bearings which were not appropriate for the application were twice installed in the cooling pumps by the service shop (id. at 37). The Company maintains that there is no reason to believe that the service shop, knowingly, twice installed non-preloaded type bearings in the cooling pumps, because the first failure of the bearings was attributed to an inadequate oil level (Company Brief at 38). Furthermore, the Company maintains that the service shop's error does not rise to the level of imprudence (Company Brief at 38, 39; Company Reply Brief at 9). Rather, the Company maintains that the service shop's personnel acted reasonably because they did not deliberately perform the error (Company Brief at 38, 39). The Company also maintains that, it is not exactly known what caused the service shop to perform the error (id.).

The Company asserts that Department precedent does not hold the Company to a standard of perfection, but rather one of reasonableness, and that the standard for prudent utility behavior does not require the Company to run its business without error (id. at 9, 10). Therefore, the Company maintains that there should not be a disallowance of replacement power costs associated with the November 7, 1993 outage at New Boston 2 (id. at 39).

iv. Analysis and Findings

The record indicates that the cooling pumps failed after the 1993 major overhaul due to the installation of non-preloaded type bearings that were not appropriate for the cooling pumps. The record shows that Ingersoll had recommended, in 1963, that preloaded type bearings be installed in place of non-preloaded type bearings if a redesign occurred that would change the mechanical loading on the cooling pumps' bearings (Exh. BE-PANEL-18; Tr. 3, at 43, 44, 48, 138). The record shows that, after 1966, Ingersoll implemented a redesign of the pumps (Tr. 3, at 44, 45). The record also shows that the design change was not reflected on the parts list for the cooling pumps used by Ingersoll's repair shop in responding to the initial bearing failures (id.).

The Department finds that Ingersoll was imprudent in failing to ensure that the cooling pumps' design change was reflected on the materials list for the cooling pumps so that proper bearings could have been installed by Ingersoll's repair shop. The Company failed to present any evidence that this oversight by Ingersoll was reasonable.

As discussed in Section II.A. above, a company must refund to ratepayers incremental replacement power costs that result from imprudence committed by its independent contractors to whom the company delegates the responsibility for original or repair work. A company may not insulate itself from responsibility for the conduct of its business by engaging contractors. Section 94G of G.L. c. 164 applies with equal force to a company's independent contractors on the principle that providing electric service is part of an electric company's "nondelegable statutory obligations."

Accordingly, the Department finds that the Company is responsible for the imprudent action of its contractor. The Department orders the Company to refund all replacement power costs, with interest, associated with the three days of forced outage time, that occurred on November 7, 1993 and continued on November 13, 1993, at New Boston 2.

4. Mystic 6

a. Introduction

Mystic 6 is a 141 MW fossil unit located at Mystic Station, Everett, Massachusetts. The unit has been in commercial operation since 1961, and is owned and operated by the Company (Exhs. BE-PANEL-1, at 27; BE-PANEL-25, at 3).

During the 1993-1994 performance year, Mystic 6 experienced a planned outage, an unplanned outage, and a series of deratings (Exh. BE-PANEL-36). The planned outage was a 23-day boiler overhaul that was originally scheduled to commence on April 30, 1994, but actually started on February 12, 1994 (Exh. BE-PANEL-1, at 41). The overhaul was rescheduled when, on February 8, 1994, Mystic 6 experienced an unplanned outage due to failure of its main transformer; the Company rescheduled the planned overhaul to coincide with work to be done in response to the forced outage (id.). Work that comprised the planned outage was completed on March 6, 1994, but the outage continued because the failed transformer was still under repair (id. at 42). On March 22, 1994, the Company decided to remove Mystic 5 from service and to reactivate Mystic 6 using the main transformer from Mystic 5 (id. at 38). On April 10, 1994, Mystic 6 was returned to service using Mystic 5's main transformer (Mystic 5 remained out of service until September 24, 1994, when the refurbished Mystic 6 transformer became available for operation) (id. at 39, 42). The Company is not seeking recovery of the replacement power costs associated with the unplanned outages at Mystic 5 and 6 caused by the failure of the main transformer at Mystic 6 (Exh. BE-PANEL-1, at 38, 39, 41, 42).[30]

Incidents on November 1, 1993, and November 27, 1993, led to nine equivalent outage days of deratings related to problems with the bearings of a boiler feed pump

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[30] In Boston Edison Company, D.P.U. 95-1A (1995), the Company refunded to ratepayers $800,000 representing a preliminary estimate of the replacement power costs, with interest, associated with the unplanned outages at Mystic 5 and 6 caused by the failure of the main transformer at Mystic 6. Subsequently, in Boston Edison Company, D.P.U. 95-1D (1995), the Company identified as $360,000 the final, more accurate calculation of the replacement power costs associated with the Mystic 6 transformer failure.

(Exhs. BE-PANEL-1, at 40; BE-PANEL-36). The Attorney General addressed on brief only these two incidents (Attorney General Brief at 26-28).

The Department finds no evidence of unreasonable actions in connection with the February 12, 1994 boiler overhaul outage or the February 8, 1994 unplanned outage at Mystic 6. A discussion of the two November 1993 incidents follows.

b. The Failures of the Boiler Feed Pump Bearings

i. Background

On November 1, 1993, Mystic 6 was shut down because one of the two boiler feed pumps failed during operation (Exh. BE-PANEL-37, at 1). There are two identical boiler feed pumps at Mystic 6, whose purpose is to deliver feedwater into the boiler (Exh. BE-PANEL-25, at 4). Mystic 6 is able to operate at up to 50 percent of its full capacity on one of the two boiler feed pumps when the other pump is out of service (id.). Therefore, approximately three hours after the failure of one of the boiler feed pumps occurred, Mystic 6 was returned to service using the remaining operable boiler feed pump, and the unit was derated to 50 percent of its normal capacity (Exhs. BE-PANEL-1, at 40; DPU-32).

The Company disassembled the failed boiler feed pump and discovered that the outboard bearing of the pump had overheated and failed, and that the pump shaft was scored (Exh. BE-PANEL-37, at 1).[31] The damaged components were repaired or replaced and, on November 13, 1993, after an oil flush of the refurbished boiler feed pump had been done, the pump was returned to service (id.; Exh. DPU-32). According to the Company, the November 1, 1993 incident resulted in 140.9 equivalent outage hours (Exh. DPU-32).

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31 There are two bearings, an inboard bearing and an outboard bearing, that support the pump shaft from both ends (Exh. AG-52; RR-DPU-20). In addition, a thrust bearing supports the shaft at the outboard end (id.).

The Company attributed the failure of the bearing to the contamination of the bearing with debris, such as oxides or other residual materials, that might have accumulated on the walls inside the oil pipe through which lubricating oil was supplied to the bearings (Exh. BE-PANEL-37, at 2; Tr. 4, at 7-9, 110). According to the Company, the residual material most likely loosened and migrated with the oil flow into the bearing (Exh. BE-PANEL-37, at 2; Tr. 4, at 7-8). The Company concluded that the contamination of the bearing was the most likely cause of its failure because the pump had operated continually for a relatively long time, more than 17 hours, before the bearing overheated (Exh. BE-PANEL-37, at 1-2).

The Company explained that, although an oil filter was installed inside the oil pipe to prevent contamination of the bearings, the filter could not have prevented the November 1, 1993 bearing failure because the filter was installed upstream of where the debris originated (Tr. 4, at 9-10; RR-DPU-20). The Company also explained that, prior to November 1993, the Company had never cleaned and inspected the components of the oil pipe for any residual material on the internal surface of the pipe (Tr. 4, at 10). However, at the hearings, the Company's witness, Mr. Bedard, mentioned that he did not know whether anyone, in fact, observed debris in the oil when the failed bearing was discovered (id. at 59-60).

On November 27, 1993, another failure of the same boiler feed pump occurred at Mystic 6 (Exh. BE-PANEL-1, at 40). The thrust bearing of the pump overheated and failed after more than 24 hours of continuous operation (Exh. BE-PANEL-37, at 6-7). The Company determined that the highest temperature of the thrust bearing was 175EF before the pump was removed from service (id. at 6, 8). The Company concluded that a local hot spot might have developed inside the bearing which led to its failure (id. at 7). The Company explained that many different causes, such as misalignment of the thrust bearing and the pump shaft, an insufficient level of the lubricating oil, or debris in the oil, might have led to the development of the hot spot on the bearing (Tr. 4, at 15-19). However, no root cause investigation of the November 27, 1994 incident was performed (id. at 18, 19, 62, 63).

The Company explained that it did not perform an in-depth investigation of the root causes of the overheating of the thrust bearing because the Company did not believe that it was necessary (id. at 65). In addition, the Company's witness, Mr. Bedard, explained that the thrust bearing is a relatively small bearing, and that its exposure to a high temperature left insufficient material for further analysis (id. at 12, 63). According to the Company, after the November 27, 1993 incident occurred, the Company focused on resolving the problem and preventing it from recurring rather than on the root cause analysis (id. at 66). The Company's witness, Mr. Embriano, explained that, typically, BECo does not allocate additional funds for a root-cause analysis if the Company is confident, as it was in this case, that the issue had been resolved (id. at 66).

The Company replaced or repaired the failed components; completely disassembled, inspected, and cleaned the lubricating oil system; and, based on the previously experienced problems with the outboard bearing, performed a twelve-hour oil flush of the bearing's lubricating oil system (Exh. BE-PANEL-37, at 6). The Company also revised its procedure to flush the oil system of the boiler feed pumps (Tr. 4, at 10). Since November 27, 1993, the Company has started to perform a complete inspection and cleaning of the internal surfaces of the piping prior to commencing the extensive flush of the system (id.). According to the Company, these measures have resulted in an effective resolution of the problems and prevented recurrence of the bearing failures (id. at 15, 66). The derating of

Mystic 6 associated with the failure of the boiler feed pump lasted from November 27, 1993 through December 3, 1993, and resulted in 66 equivalent outage hours (Exhs. BE-PANEL-1, at 40; DPU-32).

ii. Attorney General's Position

The Attorney General did not identify on brief any particular imprudent action by the Company that might have caused the November 1, 1993 and the November 27, 1993 incidents. However, the Attorney General argues that the Company should refund to ratepayers the replacement power costs associated with the November 1, 1993 and the November 27, 1993 incidents because the Company failed to demonstrate that these two incidents did not result from imprudent actions by the Company (Attorney General Brief at 28). The Attorney General asserts that the Company may not expect to recover the replacement power costs, claiming that the root causes of the boiler feed pump failures have not been identified because no root-cause analysis of the incidents was conducted (id.).

iii. Company's Position

The Company maintains that its investigation of the causes of the boiler feed pump bearing failures was reasonable, appropriate, and adequate to determine and implement effective corrective actions (Company Brief at 40). The Company argues that it did conduct a root cause investigation of the bearing failures: it issued the incident reports which addressed the details of the bearings' operating history, the results of their physical examinations, and the evaluation of the failures by maintenance and operations personnel (id.). The Company agrees that the root causes of the bearing failures were not conclusively determined, but argues that the root cause analysis is less important than the Company's success in implementing the corrective measures to prevent the bearing failures from recurring (id.). The Company asserts that there is no basis for disallowance of any replacement power costs associated with the failures of the bearings of the boiler feed pump at Mystic 6 (id. at 41).

iv. Analysis and Findings

(A) The November 1, 1993 Incident

The record shows that, on November 1, 1993, a shutdown and a subsequent derating of Mystic 6 resulted from the failure of one of the two boiler feed pumps (Exh. BE-PANEL-37, at 1). The record also shows that the pump became inoperable because the outboard bearing of the pump was overheated and failed during operation (id.).

According to the record, the Company determined that the debris that had accumulated on the walls inside the oil pipe, which then separated and migrated with the oil flow into the bearing, was the most likely root cause of the November 1, 1993 bearing failure (Exh. BE-PANEL-1, at 40; Tr. 4, at 7-9, 110). The record shows that the Company based its conclusion regarding the most likely cause of the bearing failure on the fact that the pump had operated continually for more than 17 hours before the bearing became overheated and failed (Exh. BE-PANEL-37, at 1-2). In addition, the Company recognized that the oil filter located inside the oil pipe could not have prevented the migration of the debris into the bearing because the filter was installed upstream of where the debris originated (Tr. 4, at 9-10). The Company also explained that, prior to November 1993, the Company had never cleaned and inspected the components of the oil pipe, which might have contributed to the undetected accumulation of the residual material on the inside surface of the oil pipe
(id. at 10). The record also shows that implementation of the new procedure for the oil pipe inspection and cleaning completely resolved the problem after the November 1993 incidents (id.

at 10, 66). Therefore, based on the record, the Department finds that the debris contamination of the outboard bearing was the most likely root cause of the November 1, 1993 bearing failure.

However, the record contains no evidence that the Company knew or should have known, prior to November 1, 1993, that residual materials might have accumulated on the walls inside the oil pipe, which might have loosened and migrated with the oil flow into the bearing. In addition, there is no evidence that the oil pipe filter was inappropriate or was installed inappropriately. Therefore, the Department finds no evidence that separation of the debris from the internal surface of the oil pipe and its migration with the oil flow into the outboard bearing causing its overheating and failure could have been reasonably anticipated and avoided. Accordingly, the Department finds no evidence of any unreasonable or imprudent actions by the Company that caused the November 1, 1993 incident.

(B) <u>The November 27, 1993 Incident</u>

The record is clear that Mystic 6 was derated by 50 percent from November 27, 1993 to December 3, 1993, because one of its boiler feed pumps failed on November 27, 1993. According to the record, the pump became inoperable because its thrust bearing overheated and failed. The record shows that a local hot spot most likely developed on the thrust bearing, but the Company was unable to determine a root cause of the hot spot because it performed no root cause investigation (Tr. 4, at 18, 19, 62, 63).

The Company argues on brief that it did conduct a root cause investigation of the November 27, 1993 bearing failure. However, the Company produced no evidence that it had conducted an in-depth root cause investigation of the November 27, 1993 incident that might have led to the determination of the root cause of the bearing failure. The only document in which the failure of the thrust bearing was addressed was an incident report, which stated that no root cause of the bearing failure was found. During hearings, the Company speculated that the local hot spot might have developed because of misalignment of the thrust bearing components, insufficient level of the lubricating oil, or debris in the oil (Tr. 4, at 15-19). However, no such discussion or evaluation of possible root causes of the local hot spot in the thrust bearing was incorporated in the incident report (Exh. BE-PANEL-41; Tr. 4, at 113-114). Moreover, the record shows that the Company deliberately decided not to conduct an investigation of the root causes of the thrust bearing failure because the Company believed it to be unnecessary (Tr. 4, at 65). The record shows that the Company considered it more important to resolve the problem rather than to determine its root cause (id. at 113-114).

Although the record in this proceeding does not contain sufficient evidence to conclude that any specific unreasonable action by BECo resulted in the failure of the bearing on November 27, 1993, it does show that the Company did not perform an investigation of the root cause of the overheating of the thrust bearing (id. at 65). The Company made an attempt to justify its decision not to pursue a root cause investigation by the lack of the material available for analysis after the bearing had failed, and by the substantial costs associated with the root cause investigation. However, the Company presented no evidence in support of these claims. The Department finds that the Company has failed to demonstrate that it made all reasonable or prudent efforts to thoroughly investigate the thrust bearing failure and that the replacement power costs associated with the November 27, 1993 incident were incurred reasonably.

The statute places on a company the burden to prove that it made all reasonable or prudent efforts consistent with accepted management practices to achieve the lowest possible costs to its customers. G.L. c. 164, § 94G(b). Pursuant to G.L. c. 164, § 94G(b), "the burden of proof shall be on the utility company to demonstrate the reasonableness of energy expenses sought to be recovered through fuel charges." Consistent with the Department precedent, the Department interprets this standard as requiring the company to demonstrate that it made all reasonable or prudent efforts to thoroughly investigate the outage and that its failure to identify a root cause of the outage was not unreasonable. See Boston Edison Company, D.P.U. 94-1A-1 (1995), at 46-47.

Therefore, the Department finds that the Company has failed to sustain its burden of proof in this proceeding with regard to the November 27, 1993 incident. Accordingly, the Department directs the Company to calculate the replacement power costs associated with the derating of Mystic 6 from November 27, 1993 to December 3, 1993, and to refund them to ratepayers, with interest.

5. Mystic 7

a. Introduction

Mystic 7 is a 592 MW fossil unit located at Mystic Station, Everett, Massachusetts. The unit has been in commercial operation since 1975, and is owned and operated by the Company (Exhs. BE-PANEL-1, at 27; BE-PANEL-25, at 3).

During the 1993-1994 performance year, Mystic 7 experienced a planned outage, three unplanned outages, and several incidents that led to the restriction in the unit's output (Exh. BE-PANEL-1, at 43-49). The planned outage was necessary in order to inspect the boiler (Exh. BE-PANEL-1, at 48). The planned outage was scheduled for 13 days, from October 11, 1994 to October 23, 1994, and was completed on schedule

(Exhs. BE-PANEL-1, at 48; BE-PANEL-65). Two of the unplanned outages were necessary to repair boiler tube leaks in the secondary superheater (Exhs. BE-PANEL-1, at 46, 47; BE-PANEL-41). One commenced on February 17, 1994 and was completed in three days (id.). The other commenced on March 11, 1994 and was completed in four days (id.). The other unplanned outage, during which a failure of the Induced Draft ("ID") Fan Motor Coupling ("coupling") was addressed, occurred between November 1, 1993 and December 30, 1993, and involved both output restrictions and forced outages having a total equivalent lost availability of 33 days (Exhs. BE-PANEL-1, at 43; BE-PANEL-41). The incidents that led to restrictions in the unit's output occurred from July 25, 1994 to August 9, 1994 (Exhs. BE-PANEL-1, at 47-48; BE-PANEL-41). During that period, the Company addressed the contamination of the cooling water intake canal due to a high amount of mollusk shells, which resulted in an equivalent lost availability of eight days (Exhs. BE-PANEL-1, at 47-48; BE-PANEL-41; BE-PANEL-49).

The Attorney General addressed on brief only the unplanned outage that occurred on November 1, 1993, which involved both output restrictions and forced outages, as a result of the ID coupling failure (Attorney General Brief at 41). The Department finds no evidence of unreasonable actions in connection with the October 11, 1994 planned outage, February 17, 1994, or March 11, 1994 unplanned outages, or incidents of unit output restrictions that occurred from July 25, 1994 to August 9, 1994 at Mystic 7. A discussion of Mystic 7's November 1, 1993 unplanned outage, follows.

b. The Failure of the Induced Draft Fan Motor Coupling

i. Background

This section addresses the November 1, 1993 unplanned outage, which involved both output restrictions and forced outages as a result of the failure of the ID coupling. The section also addresses the October 12, 1993 failure of the ID coupling that occurred during the previous performance year. In Boston Edison Company, D.P.U. 94-1A-1, at 58, the Department ordered the Company to continue its investigation into the October 12, 1993 failure of the ID coupling and report its findings in its next performance review filing. As discussed below, the ID coupling's failure experienced on October 12, 1993 during the previous performance year is related to the coupling's failure experienced on November 1, 1993.

(A) The October 12, 1993 Failure of the Coupling

On October 12, 1993, Mystic 7's output was restricted due to problems with an ID fan. D.P.U. 94-1A-1, at 54 (1994). The two identical variable speed ID fans at Mystic 7 remove combustion gases from the boiler and discharge these gases to the chimney. Id. Each ID fan is mechanically connected to a motor through a coupling assembly, which is designed to instantly disengage the fan from the motor under abnormal operation to prevent damage to the equipment. Id. In particular, four shear pins, which are the essential components of the coupling, establish the mechanical link between the motor's shaft and the fan's shaft. Id. at 55. As is typical for the application of shear pins, the pins are manufactured with a reduced cross-sectional area and are thus designed to break to prevent exceeding the maximum torque rating of the coupling. Id. On October 12, 1993, an ID fan became disengaged from its drive motor when the coupling's four shear pins broke during normal operation. Id. Mystic 7 continued to operate, but BECo had to reduce the unit's output. Id.

The ID fan assembly and the variable speed drive motor were new pieces of equipment installed during the Spring 1993 Overhaul and were intended to correct power restrictions at Mystic 7 during peak summer periods as a result of the original ID fans' inability to provide sufficient boiler air flow during peak summer periods (Exh. BE-PANEL-47; RR-AG-6; Tr. 4, at 27, 68, 69; See also D.P.U. 94-1A-1, at 55 (1994)). When the Company decided to seek out new equipment that would satisfy Mystic 7's boiler air flow demands, the Company developed, with the aid of a motor consultant, bid specifications to meet the requirements of the application (RR-AG-8; RR-AG-9; Tr. 4, at 69).

On September 26, 1989, the Company issued a request for quotation ("RFQ") and bid specifications which contained the necessary functional operating criteria such as air flow, motor stator temperature, starting torque, pull out torque, efficiency, and reliability, to six equipment manufacturers (id.). The Company's bid specifications required that a motor and drive system be supplied capable of developing sufficient torque to fulfill acceleration and deceleration response requirements of the coupled load without exceeding the normal system operating limits and that a "torsional vibration analysis study" be performed (RR-AG-9, Sections 1, 3). The torsional vibration analysis study is an analysis of mathematical calculations which would theoretically identify any harmful torques and vibration on the drive motor, driven equipment rotors, shafts, couplings, and foundation mountings at all speeds from standstill to maximum rated synchronous speed during optimum operation coupled with vane control (RR-AG-9, Sections 1, 3 at 44; Tr. 4, at 33, 34). The Company required that a review of the study be performed to identify design changes needed to eliminate torque or vibration problems by making changes to the drive motor, driven equipment rotors, shafts, couplings, and foundation mountings (RR-AG-9, Sections 1, 3). The Company's bid specifications also required resilient matching couplings for coupling the drive motor to the driven equipment selected to eliminate harmful torques and vibrations from speeds zero to maximum based on the results of the torsional vibration analysis study (Exhs. BE-PANEL-67; DPU-35; RR-AG-9, Section 3, Attachment A1-37). In addition, the bid specifications required that the couplings be of the Koppers Holset type and have rubber blocks or similar material to produce a nonlinear angular deflection-torque characteristic (Exhs. BE-PANEL-67; DPU-35; RR-AG-9, Section 3, Attachment A1-37). Resilient matching couplings, similar to the Holset type and manufactured by Koppers Engineered Products, enable the coupling to assume relatively large torsional deflections under torque and provide resilience and damping of torsional vibrations (Exh. BE-PANEL-67; Tr. 4, at 72). A Holset type resilient matching coupling is constructed of two matching halves bolted together, and includes specially designed, elastomer type, resilient drive blocks, which deform under torque and result in the coupling's ability to carry high torque load with resilience (Exh. BE-PANEL-67; Tr. 4, at 72).

In order to judge the expected reliability characteristics of competing equipment, the Company also required a reliability analysis report indicating reliability indices, expected service life, an installation list of equipment similar in design and service conditions, and a quality assurance program involving inspection, system level-to-component level testing, and documentation, which would ensure that the equipment furnished under the bid specifications meets operating requirements (RR-AG-9, Sections 4, 6). The required quality assurance program also applied to subcontracted, or subsupplier, items and services, and indicated that no bid specification deviations and non-conformances could be made until approved (id.).

On October 17, 1989, Asea Brown Boveri ("ABB") responded to the Company's RFQ (RR-AG-9). ABB's response specified a minimum "Mean Time To Failure" calculation of 30,000 hours and the use of a Holset type resilient coupling, which had bolts making the coupling rigid with one half of the coupling mounted to the motor and the other half of the coupling to be shipped to the fan manufacturer for mounting (Exh. DPU-35; RR-AG-9, ABB bid response, at 6, 57, 58; Tr. 4, at 72).

The Company selected ABB to supply the equipment (RR-AG-9; Tr. 4, at 69).[32] The equipment consists of two 33 ton fans manufactured by Howden of Canada, two synchronous 22 ton 7350 horsepower motors manufactured by ABB, two drive control houses, two lube oil skids, inlet and outlet dampers, associated duct work, and two motor-fan couplings furnished by ABB but manufactured by Kop-Flex, a subsupplier per ABB's requirements (Exhs. BE-PANEL-1, at 43-44; AG-54). The Company explained that ABB's assessment of the risk and potential damage in case of a motor short-circuit and drive system electronic failure led ABB to recommend the additional feature of the shear pin (breakaway) type coupling design for protection rather than the Koppers Holset type resilient matching couplings, which had bolts making the coupling rigid (Exh. DPU-35; RR-DPU-21; Tr. 4, at 21, 72, 86). The equipment was installed under the technical direction of ABB during the Spring 1993 Overhaul (Exh. BE-PANEL-47; See also, D.P.U. 94-1A-1, at 55 (1994)).

During hearings held in D.P.U. 94-1A-1, the Company described a few possible scenarios of the ID fan's failure. D.P.U. 94-1A-1, at 56 (1994). One possible scenario involved misalignment of the coupling and resultant shear pin failure, because metallurgical analysis of the failed shear pins revealed that they had failed due to fatigue. Id. Despite the fact the Company and ABB

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[32] The record demonstrates that, at the time that the Company selected ABB to provide the ID fan system, the Company was not aware that ABB had no prior experience with this particular ID fan design configuration (RR-AG-6; RR-AG-7; Tr. 4, at 27-31). The Company was not informed by ABB of this fact until after the initial operating problems with the new Mystic 7 ID fan design (id.).

performed an extensive root cause analysis of the event involving various independent consultants, the Company and ABB had been unable to identify a specific root cause of the failure of the ID fan that occurred on October 12, 1993 (RR-AG-8; See also, D.P.U. 94-1A-1, at 55-56 (1994)). Subsequently, two more shear pin incidents at both ID fans occurred. D.P.U. 94-1A-1, at 56 (1994). The ID fan's failure was identified by the Company as a continuing problem with both the Company and ABB actively searching for its root cause. Id.

(B) The November 1, 1993 Failure of the ID Coupling

Between November 1, 1993 and December 30, 1993, Mystic 7 experienced several incidents involving both output restrictions and forced outages similar to the October 12, 1993 incident in which the ID fan became disengaged from its drive motor (Exhs. BE-PANEL-1, at 43, 44; BE-PANEL-3; BE-PANEL-41; Tr. 4, at 76). That is, the fan became disengaged from its drive motor when the coupling's four shear pins broke during operation (Exh.BE-PANEL-1, at 44). However, the Company ruled out motor and fan misalignment as the possible cause of shear pin failures since the motor and fan were aligned after the October 12, 1993 incident (id.). Furthermore, vibration analysis of the ID fan system and material analysis of the shear pins indicated that excessive vibrations did not exist and that the shear pins satisfied their specifications (id.). Furthermore, the material analysis indicated that the shear pins were of same Rockwell hardness[33] and that all were manufactured and heat treated from the same material (Exh. BE-PANEL-44, at 1).

In order to analyze the failure mechanism and obtain on-line operating data, ABB and the coupling manufacturer recommended, in December of 1993, that after each failure, the coupling's

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33 According to Marks' Standard Handbook for Mechanical Engineers, Rockwell hardness measures the surface hardness, or resistance to penetration, scratching, machining, wear, abrasion, or yielding, in terms of the depth of penetration of a hardened steel ball or special stylus.

shear pins be replaced with shear pins having higher fatigue limits than those that were originally designed to allow for a longer operating time between failures (Exhs. BE-PANEL-1, at 44; BE-PANEL-52; Tr. 4, at 84). In response to this recommendation, the Company decided, in January of 1994, to replace the shear pins prior to their failure (Exh. BE-PANEL-51, at 22, 23, 26, 27; Tr. 4, at 84). This shear pin replacement plan was instituted by the Company and was to be used until a permanent solution was developed (Exh. BE-PANEL-1, at 44; Tr. 4, at 70).

As the investigation continued, the investigation focused on the motor and the torque stresses developed by the motor (Exh. BE-PANEL-1, at 44). Upon performing testing on the actual operating ID fan system, the extent and magnitude of the torque stresses which led to the stress induced fatigue failure of the shear pins were obtained by ABB and the coupling supplier (Exhs. BE-PANEL-45, at 29; BE-PANEL-53; DPU-35; RR-DPU-21; Tr. 4, at 32, 33, 88). The results led ABB to believe that the problem was with the design of the original coupling with respect to this particular application (Exh. BE-PANEL-1, at 44-45).

In December 1994, upon the Company's request, ABB provided to the Company, a revised torsional analysis, similar to an analysis ABB provided in the past for New Boston station (Exhs. BE-PANEL-51, at 1, 24; BE-PANEL-52, at 23). The intent of ABB's revised torsional analysis, performed after the shear-pin-type coupling failure, was to "[c]larify whether the original shear pin coupling could be replaced by a non torque-limiting coupling or not" (Exh. BE-PANEL-52, at 24). ABB performed the revised analysis based on the existing coupling but without any torque limiting devices, that is, shear pins (id.). ABB and the coupling manufacturer later determined that the shear-pin-type coupling design was not suitable for the application because the torque stresses present led to the stress induced fatigue failure of the shear pins (Exhs. BE-PANEL-53;

DPU-35; AG-54; RR-DPU-21; Tr. 4, at 31, 32). Recommendations were made in early March 1994 to replace the ID coupling equipped with shear pins with a modified solid type ID coupling[34] having its halves bolted together and no shear pins, and in late April 1994, the modified ID coupling was installed (Exhs. BE-PANEL-1, at 45; BE-PANEL-51, at 20; BE-PANEL-52; Tr. 4, at 70, 74). In addition, the software, which controls the motor's magnetic flux over the motor's speed range, was changed to limit the magnetic flux at torsional critical speed range (Exhs. BE-PANEL-52, at 26; DPU-35; Tr. 4, at 75, 78-80). The torsional critical speed range is the range of motor speeds at which torque stress peaks of the motor's shaft are reached (Exh. BE-PANEL-52, at 26, 43). The Company explained that this would limit the motor's torque capabilities at the torsional critical speed range and was necessary to protect against excessive torque and possible damage to the motor's shaft during a phase-to-phase motor short circuit or drive system electronic failure with the modified coupling in place (Exhs. BE-PANEL-1, at 45; BE-PANEL-52, at 26; Tr. 4, at 78-80). After the changes were made, the ID Fans continued to operate without further problem through the end of the performance year (Exh. BE-PANEL-1, at 45).

ii. Attorney General's Position

The Attorney General asserts that the problem with the new ID fans, which were manufactured by ABB and installed at Mystic 7 during the 1993 major overhaul, centered on the motor-to-fan coupling (Attorney General Brief at 29). The Attorney General claims that the manufacturer's design of the shear-pin-type motor-to-fan coupling was inadequate for use at Mystic 7 (id. at 30). The Attorney General notes that the shear pins were eventually eliminated

[34] The modified coupling is similar to a Koppers Engineered Products, MAX-C Holset Resilient Shaft, coupling (Exh. BE-PANEL-67; Tr. 4, at 72).

and a solid coupling device was installed (id. at 29). The Attorney General maintains that the Company required ABB to supply equipment that meets the performance requirements of all operational modes, and that neither ABB nor the coupling manufacturer fully understood the dynamics of Mystic 7's operation; thus ABB furnished equipment that could not meet the performance requirements (id. at 29, 30).

The Attorney General contends that the lost availability at Mystic 7, caused by the failure of the ID fan, resulted from imprudent actions by the Company's contractor, ABB and the coupling manufacturer (id. at 30, 31). The Attorney General refers to the Company's intention to seek reimbursement for financial damages from ABB as a result of the ID fan's failure and indicates that, regardless of whether the Company achieves any reimbursement, the record demonstrates ABB's imprudence in designing the ID fan (Exh. BE-PANEL-47, at 3; Attorney General Brief at 31, citing Exh. AG-54).

The Attorney General further maintains that, because ABB's imprudence is imputable to the Company, the Company must refund to ratepayers replacement power costs that resulted from imprudence committed by its contractor, ABB (Attorney General Brief at 31). The Attorney General argues that the Company should not be allowed to recover damages from the manufacturer and also replacement power costs from its ratepayers (Attorney General Reply Brief at 9).

iii. Company's Position

The Company argues that there is no basis for the disallowance of costs as a result of the ID fan problems experienced at Mystic 7 during the performance year (Company Reply Brief at 9). The Company states that, when it developed the bid specifications for Mystic 7's new ID fans, it identified functional operating criteria such as air flow, stator temperature, reliability, and efficiency, and that the Company selected ABB to furnish the equipment after reviewing ABB's bid submittal (Company Brief at 41). The Company states that although the motors were tested prior to the installation of the ID fan system, the ID fan system could not be assembled and tested by ABB prior to its installation since such testing would require the need to build a test facility that would replicate Mystic 7's boiler air flow demands, that the individual system components would had to have been delivered from different locations to the test facility, and that ABB did not have such a test facility (id. at 41, 42, RR-DPU-21). Furthermore, the Company argues that the ID fan system is a dynamic system and could be effectively tested only in operation at Mystic 7 (id. at 41, 42). The Company claims that, even if a test facility were constructed, it is unlikely that the testing at the facility would have revealed the same stress induced fatigue type failure mechanism experienced by the ID fan system's coupling, since it is unlikely that the testing would have run for a period of time to produce the stresses (RR-DPU-21).

The Company states that, even though the ID fan system design was excellent in concept, and was supported by a valid engineering analysis, some problems were to be expected with the ID fan system given that the system included new technology and that it was the first time the shear-pin-type coupling design was used in this type of system (Exhs. BE-PANEL-1, at 45; DPU-35; Tr. 4, at 33, 34; Company Brief at 41). The Company claims that, following the identification of a problem with the shear pins, the Company's efforts to resolve the problem were both aggressive and persistent (Company Brief at 41, 42). The Company notes that, since the system was placed on line, ABB was able to gather the operational data necessary to redesign the coupling (id. at 42). The Company states that, in the period since ABB's changes were implemented, the performance of the new ID fan system with the redesigned

coupling has improved (id.). The Company maintains that, although "the Mystic 7 installation was not the most appropriate application for a shear pin coupling," neither ABB nor the Company could have anticipated a design problem with the shear pin coupling since it was based on established engineering analysis and was a first-of-a-kind used in this type of system (Exhs. BE-PANEL-1, at 45; AG-54;
Tr. 4, at 22; Company Brief at 42).

The Company asserts that it has not admitted any imprudence on the part of ABB, and that there is no evidence in the record to support a finding of imprudence on the part of ABB or the Company (Company Brief at 42; Company Reply Brief at 10). The Company further asserts that its intention to seek reimbursement for economic damages from ABB does not imply Company imprudence with respect to the unit outages, and thus, the disallowance of replacement power costs (Company Brief at 42, 43). The Company maintains that both ABB and the Company's actions were reasonable at all times based on the information available to them at the time (id. at 42).

iv. Analysis and Findings

The record is clear in this proceeding that the root cause of the problems experienced with the new ID fan system was failure of the ID coupling's shear pins under torque stresses developed by the new ID fan system under operation. The record demonstrates that, in seeking to replace Mystic 7's ID fans, the Company developed detailed bid specifications for the new systems (RR-AG-9, Section 1; Tr. 4, at 88-89). The RFQ anticipated that ABB would supply equipment that would satisfy the bid specifications in order to meet the functional operating criteria of the system (id.). As part of the bid specification, the Company specified a Koppers Holset type ID coupling (Exh. DPU-35; RR-AG-9, Section 3, at 44; Tr. 4, at 72). ABB supplied an alternative ID coupling that was outside of the bid specifications and that was later found to be inadequate.

The record demonstrates that, when the Company chose ABB to supply the new ID fan system, the Company was unaware of whether an analysis had been performed by ABB to demonstrate that the proposed replacement ID coupling would meet the required operational requirements of the bid specification (Tr. 4, at 33-36, 69, 86-90, 100). Moreover, in the course of this proceeding the Company has not presented evidence that an appropriate design analysis was performed by ABB or the Company to support the alternative ID coupling that was selected for the ID fan application.

The Department finds that the Company has failed to meet its burden of proof to demonstrate that its actions, and those of its contractor, ABB, were reasonable. More specifically, the Company has failed to demonstrate that the analysis ABB performed when recommending the shear-pin-type ID coupling over the direct-bolted-type ID coupling to the Company was adequate for Mystic 7's ID fan system.

Absent a presentation that a thorough design analysis was performed by ABB or the Company demonstrating, at least analytically, that it was reasonable to replace the Koppers Holset shear-pin-type ID coupling that the Company had selected for the ID fan system application, the Department must assign to the Company responsibility for the forced outages and deratings which occurred at Mystic 7 during the period October 12, 1993, to December 30, 1993. Ratepayers cannot be asked to support the costs associated with this unjustified equipment failure. Therefore, the Department orders the Company to refund all replacement power costs, with interest, associated with the forced outages and deratings which occurred at Mystic 7 during the period October 12, 1993, to December 30, 1993.

6. Other Units

During the course of this investigation, the Department also reviewed data and exhibits submitted concerning other generating units of BECo for which goals were established in D.P.U. 93-146. The Department finds no evidence at this time that any outage or derating at these units during the performance year resulted from unreasonable or imprudent actions.

III. ORDER

Accordingly, after due notice, public hearing, and consideration, it is

ORDERED: That all incremental replacement power costs incurred by Boston Edison Company attributable to (1) the extension to the November 5, 1993 unplanned outage at Pilgrim from November 8, 1993 through November 9, 1993; (2) the February 23, 1994 through February 26, 1994 portion of the February 23, 1994 unplanned outage at Pilgrim, associated with the failure of the MSIV pneumatic control system; (3) the unplanned outages of New Boston 2, from November 1, 1993 through November 9, 1993, and from November 13, 1993 through November 14, 1993, associated with the failures of the Generator Stator Liquid Cooling Pump Bearings; (4) the unplanned outage of Mystic 6 from November 27, 1993 through December 3, 1993, associated with the failures of the Boiler Feed Pump Bearings; and (5) the unplanned outages and deratings of Mystic 7 from October 12, 1993 through December 30, 1993, as described herein, be and hereby are disallowed; and it is

FURTHER ORDERED: That the Company shall in its next fuel charge filing provide for the refund to ratepayers, with interest, of any costs disallowed herein that have already been recovered through the Company's fuel charge; and it is

FURTHER ORDERED: That the Company shall continue its investigation of the causes of the four outages at New Boston 1, between May 30, 1993 and July 8, 1993, and shall report its findings to the Department.

By Order of the Department,

____
John B. Howe, Chairman

____
Janet Gail Besser, Commissioner

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).